REPUBLIC OF MOLDOVA

OPERATIONAL PROCEDURES FOR MARKET IMPLEMENTATION

Regulatory Development
and
Power Market Operations

Final Report

Prepared for:

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Operating Procedure No. 1

1 OPERATING RESPONSIBILITY AND AUTHORITY OF THE SYSTEM OPERATOR

1.1 Introduction

1.1.1 The System Operator is responsible to serve as the operator of the Moldova Power System and assume responsibility for the continued operation of the Dispatch Center, consistent with the terms of the Power Market Guidelines, Power Market Rules, the System Rules and Procedures, Good Utility Practice and applicable laws and regulations.

1.1.2 This operating procedure defines the overall parameters within which the more specific Operating Procedures can be formulated.

1.2 Principles

1.2.1 The System Operator is responsible for the day-to-day operation of the Moldova power system resources in accordance with all applicable rules and procedures.

1.2.2 To most efficiently achieve the objective of central dispatch, it is necessary that the System Operator and the Participants execute their responsibilities with a spirit of cooperation and with an understanding of the tasks to be accomplished.

1.3 General Statement of Responsibilities

1.3.1 The System Operator is responsible in matters pertaining to the central dispatch of all transmission facilities rated 110 kV and above, dispatchable load and all generating resources, including imported power, committed to Central Dispatch.

1.3.2 This assigned responsibility and authority extends to include decisions, instructions, and orders issued to Participants electronically, verbally or in writing, as required for day-to-day, minute-to-minute operation of both generation and transmission facilities.

1.3.3 Participant facilities will also contribute to Central Dispatch in accordance with approved Operating Procedures for Market Implementation, Power Market Rules and System Rules and Procedures.

1.3.4 The System Operator and Participants share a responsibility to initiate dispatch actions deemed necessary to prevent injury, loss of life, equipment damage, and/or service interruptions.

1.3.5 Consistent with the Principles and general responsibilities stated within this procedure and to assure the effectiveness of Central Dispatch through the System Operator and Participant facilities, the following dispatch assignments are made. The listed assignments include most of the fundamental responsibilities of central dispatch. It is expected that these responsibilities will receive continual review and will be updated as needed to assure efficient operation of the Moldova power system. It is further understood that all operating entities at the System Operator and Participant level share a responsibility to protect proprietary and privileged information that may unduly influence the operation of the power market system.

1.4 Transmission Operation

1.4.1 Monitor power flows on all transmission facilities operating at 110 kV and above.

1.4.2 Initiate central dispatch actions, including the commitment and/or decommitment and MW adjustment of power resources, required to insure that the facilities noted in (1.1) above are operated in compliance all rules and procedures.

1.4.3 Coordinate voltage and reactive dispatch of transmission facilities.

1.4.4 Respond to system disturbances by initiating load management procedures, including voltage reduction and load shedding.

1.4.5 Coordinate system restoration after wide spread loss of load.

1.4.6 Direct implementation and restoration of load shedding and system restoration.

1.4.7 Direct implementation and restoration of voltage reduction.

1.5 Security Analysis

1.5.1 Schedule outage for transmission facilities operating at 110KV and above based on contingency analysis that will assure reliable operation.

1.5.2 Schedule outage for maintenance of communications, computers, metering and support equipment (Operating Procedure No. 2) based upon projected system conditions.

1.5.3 Monitor power flows on transmission facilities operating at 110KV and above. Based on contingency analysis, initiate dispatch actions to assure reliable operation.

1.5.4 Schedule and administer long and short-term maintenance.

1.6 Economic Dispatch of System Operator

1.6.1 Continuously monitor the power resource loading conditions and determine the most economical allocation of power resources considering power system frequency, Moldova system load, reserve, reliability, and other power system specific requirements. The System Operator will improve economic dispatch through the utilization of participant contracts.

1.7 Automatic Generation Control (AGC)

(For the future Moldova Power System development)

1.7.1 Maintain a sufficient number of generating units on AGC to satisfy reliability, economic and tie line regulation requirements in accordance with Power Market Rules and Operational Procedures for Market Implementation. Units on AGC should be selected to achieve the best economics while maintaining system reliability and/or control performance.

1.8 Control Area Interchange

1.8.1 Schedule, monitor, and maintain the System Operator Control Area interchange with Ukraine and/or Romania while adhering to all related operating criteria.

1.8.2 Forecast inter-area exchanges, consistent with scheduling periods, (hourly, weekly, and monthly) to be used as delimiters in the scheduling of inter-area transfers.

1.9 Contract Administration

1.9.1 Monitor, schedule for delivery, and/or suspend available power contracts within Moldova power system and external contracts based upon contract availability criteria, the optimization of system economics and/or system reliability constraints.

1.10 Hydro Power Plant Operation

1.10.1 Develop and distribute the energy schedules for Costesti Hydro taking Participant contracts and loads, and system reliability into consideration in accordance with Power Market Rules.

1.10.2 Direct real-time generation control of Costesti Hydro via the generating station operators.

1.10.3 Monitor elevations as well as MWh totals and discharges at the Costesti Hydro to determine MWh availability for this unit.

1.11 Interconnection Scheduling

1.11.1 Develop and/or coordinate hourly, weekly, monthly, etc. interchange schedules for all interchange arrangements between and/or through Moldova power system participants and neighboring power systems (Ukraine and/or Romania), including emergency transactions.

1.11.2 Incorporate appropriate scheduled power contracts into the daily commitment process and communicate to all necessary external parties.

1.11.3 Maintain a record by contract of interchange activity.

1.12 Maintenance Coordination - Generation

1.12.1 Receive, recommend approval/disapproval and administer requests for long and short-term maintenance.

1.13 Generator Tests and Audits

1.13.1 Initiate and administer parameter audits on Participants' hydro and thermal generating units in accordance with Power Market Rules and Operational Procedures for Market Implementation.

1.13.2 Give authorization for participants' initiated demonstrations.

1.14 Operating Reserve

1.14.1 (For the future Moldova Power System development)

1.14.2 Maintain a sufficient amount of operating reserve. If available capacity is insufficient to provide adequate operating reserve, the System Operator will implement the various actions:

1.14.3 Action during a capacity deficiency (Operating Procedure for Market Implementation No. 4)

1.14.4 And/or Operating Reserve (Operating Procedure for Market Implementation No. 7)

1.14.5 And/or Action in an Emergency (Operating Procedure for Market Implementation No.9)

1.15 System Load Forecasting

1.15.1 Forecast and update the present day's forecast of the Moldova system hourly loads for the purpose of unit commitment and power contract scheduling in accordance with Power Market Rules and Operational Procedures for Market Implementation.

1.16 Unit Load Commitment

1.16.1 Develop commitment/de-commitment schedules for all power reswources available for central dispatch with consideration for system security and reliability constraints.

1.16.2 Supply participants with the most current commitment/de-commitment schedules.

1.16.3 Coordinate activities between the System Operator and Participant personnel on matters relative to the operation of the Participant power resources.

1.16.4 Coordinate participants recommend changes to commitment or incremental loading of power resources to maintain area voltage and or to meet thermal transmission requirements.

1.17 Unit Control Modes and Operating Limits

1.17.1 Maintain the status of all power resource control modes and operating limits on all generating units under the System Operator direct generation control.

1.17.2 Maintain operating parameters, such as minimum run times, minimum down times, response rates, etc. of all System Operator Participant power resources via the System Operator communication system.

1.17.3 Compile and maintain all necessary information, as required by System Operator Settlements Center for resources under the System Operator direct control.

1.17.4 Incorporate known generator operating restrictions into security analysis.

1.17.5 Report all necessary information to properly reflect all generating units redeclarations.

1.18 System Operator Backup Facilities

1.18.1 Develop and implement a back-up plan for all functions for which the System Operator is responsible including all necessary software, hardware and facility requirements.

1.19 Communications - Data

1.19.1 Keep dispatch data that is needed for various purposes.

1.19.2 Collect real-time data required to perform central dispatch from Participants. Operating Procedure for Market Implementation No. 16 - Metering and Telemetering Criteria defines specific requirements.

1.20 Communications - Voice

1.20.1 Provide the necessary voice communications required to issue central dispatch instructions directly to generating stations, units and power resources.

1.21 Dispatch Computers and Peripheral Dispatch Equipment

1.21.1 Be responsible for scheduling and coordinating planned outages of the System Operator, Participant computers, Data communications network, and any other equipment that deprives System Operator or Participants of normal operating data or voice communications.

1.21.2 This is further defined in Operational Procedure for Market Implementation No. 2 – Requirements for Communications, Computers and Metering.

Operating Procedure No. 2

2 MAINTENANCE OF COMMUNICATIONS, COMPUTERS, AND METERING

2.1 Introduction

2.1.1 This procedure establishes System Operator criteria for the repair and maintenance of equipment whose loss has a significant impact on the ability to reliably operate Moldova Power System.

2.1.2 The following lists types of equipment which, depending on specific roles, can be critical to system operation:

- Computers
- Metering, Telemetering and Control equipment
- Communications equipment
- Computer support equipment
- Associated equipment

2.1.3 While it is impossible to list all the conceivable contingencies that might result in failure of critical equipment, this instruction attempts to identify the equipment and give guidelines for its repair or maintenance.

2.1.4 This procedure includes provisions for allowing warranted exceptions to the established maintenance priorities for the covered equipment.

2.2 Scope

2.2.1 This procedure covers all equipment located at System Operator premises.

2.2.2 In order to promote efficient and rapid repair or maintenance of affected equipment, the following aspects of repair and maintenance work are covered:

- Criteria for repair/maintenance priority
- Establishment of Criteria
- Responsibility for repair/maintenance
- Scheduling of routine maintenance
- Day of performance of routine and emergency/unplanned maintenance
- Record keeping

2.3 Procedure

2.3.1 Criteria For Repair/Maintenance (Priority)
The following criteria identify required response times to begin repair of failed equipment. The times are based upon the importance of the equipment to system operations. This same criterion is used to prioritize requests made for equipment maintenance.

Immediate

This highest priority for repair or maintenance applies to equipment that is critical to maintain adequate system security and reasonable economic dispatch.

Regular - working hours weekdays

This intermediate priority is intended for equipment whose loss can be tolerated for limited periods of time, but which cannot or should not be tolerated for prolonged periods of time.

2.3.2 Establishment of Criteria

Under normal conditions

The criteria (priority classification) for maintenance of various equipment affecting System Operator operation should be established.

Under abnormal conditions

The System Operator control room staff has the authority and responsibility to change the established criteria. If a criterion is changed, the operator requesting the change must document it.

2.3.3 Responsibility for Repair/Maintenance

The location of the equipment fixes the responsibility for repair or maintenance in most instances. Repair or maintenance of facilities used in support of the System Operator operation but not owned by the System Operator, shall be the responsibility of the owner.

Repair Work

Equipment failures must be responded to within the time requirements prescribed in Section 1. of this document. Repair work status should be communicated between all effected parties.

Coordination of Maintenance

It is the responsibility of the System Operator to coordinate all maintenance on equipment. Coordination includes the scheduling, approval or denial of requests for regular maintenance, and the change in criteria classification in the event of emergency.

2.3.4 Scheduling of Routine Maintenance

Requests for arranging advance schedules for routine maintenance on any equipment should be submitted to the System Operator.

2.3.5 Record keeping

It is the responsibility of the System Operator to perform record keeping necessary under this procedure as required by each location.

Annex

MAINTENANCE OF COMMUNICATIONS, COMPUTERS, METERING AND BUILDING SERVICES

System Operator Computer Equipment:	Maintenance Priority
Any equipment or device that may interrupt or alter the flow of data critical to system operation	
Not supported by a back-up system	A
Supported by a back-up system	B
Control Room Printers and Loggers	B
Other Equipment at System Operator	
Fire Protection System	A
Un-interruptible Power Supply (UPS)	A
Frequency Measuring	B
Security System	B
Diagram Board Displays	B
Recorder Panel (Including Digital Displays and Clock)	A
Telephone Message Recorders	A
Voice Communications	
Dispatcher telephone circuit	A
Control Room direct dial outside lines	A
Administrative telephone circuits	B
Control, Telemetering, and Data Communications	
Data Links - System Operator Centers	A
System Operator tie line telemetering –primary circuit	A
System Operator tie line telemetering –secondary circuit	B
Weather services system	B
System Operator hydropower scheduling system	A
Communications channels for special protection systems	A
Remote terminal units and communication	A

Any equipment not specifically mentioned in this procedure will be handled on a case by case basis with the operating staffs at System Operator.

Operating Procedure No. 3

3 TRANSMISSION MAINTENANCE SCHEDULING FOR FACILITIES OPERATING AT 110 KV AND ABOVE

3.1 Introduction

3.1.1 Transmission maintenance must be coordinated to ensure that reliability is maintained at levels prescribed by Operating Procedure, *Transmission Operations.* Operating problems due to maintenance outages must be thoroughly studied. Transmission and generator maintenance must be coordinated to avoid unnecessary reductions in reliability.

3.2 Authority

3.2.1 The System Operator has the responsibility of evaluating, approving or disapproving outage schedules for all transmission facilities rated 110 kV and above.

3.3 Purpose and Scope of Procedure

3.3.1 The purpose of this procedure is to achieve the following:

a) To facilitate the long-term planning of maintenance outages of Moldova transmission facilities

b) To establish a short-term outage scheduling process that does not jeopardize the reliability of the transmission system

c) To provide guidelines for responding to emergency outages

3.3.2 The following definitions are used in this procedure:

a) Long-term maintenance outage plans are rolling projections of transmission outages for future periods. The plans are established quarterly.

b) Short-term maintenance outage schedules are specific schedules for upcoming outages.

c) An Emergency Outage is any outage that fails to satisfy the lead times necessary to fully study the implications of the outage on power system operation as required for the short-term maintenance schedule.

3.4 Long Term Outage Plans

This section describes the process for establishing and maintaining long-term outage plans.

3.4.1 Preparation/Update of Long Term Plan

The System Operator will maintain a long-term transmission overhaul and maintenance schedule on a rolling basis, which looks out at least twelve months. The schedule will be updated every quarter to incorporate the following information:

a) newly submitted or revised requests for transmission outages

b) adjustments to previously submitted requests made by the System Operator (working with the participants) for system reliability

3.4.2 Scope of Long-term Outage Plan

The schedule will include planned outages of all transmission lines and associated equipment operating at 110 kV and above. Outage of any associated equipment must be reported even though the line itself may remain in service.

3.4.3 System Operator Responsibilities

The System Operator will assign to each maintenance a date-stamp.

The date stamp will be used, if needed, to prioritize outage requests. If the participant requests a change in the date of the outage for the long term plan, the System Operator will assign a new date stamp to the outage.

Conduct Reliability Checks.

The System Operator staff will check each outage for feasibility in the scheduled time period, given load projections, the generator maintenance schedule, and previously scheduled transmission outages. If the System Operator staff determines that there is a conflict, they will work with the Participant to identify an alternate time period for the outage.

3.5 Short Term Outage Scheduling

3.5.1 The Participant wishing to do work on facilities covered by this procedure will submit a completed application form to System Operator. The System Operator will review applications for work on transmission. Outages of transmission facilities may require extensive study and coordination by the System Operator to ensure operations are within prescribed reliability criteria. Participants must coordinate equipment and manpower needed to do the work.

3.5.2 To provide adequate time for this analysis and coordination the System Operator response times will be established. Outage schedule must be acted upon in a timely manner by the System Operator to provide Participants with adequate lead times.

3.5.3 When the review and reliability study has been completed, the System Operator will communicate its conclusions to the appropriate participants.

3.6 Emergency Outages

3.6.1 An Emergency Outage is any outage that fails to satisfy the lead times as identified in previous section.

3.6.2 There are two types of emergency outages:

c) The obvious failure of a piece of transmission equipment that comes out of service on its own or requires immediate operator intervention to remove it from service.

d) The discovery of a problem that needs to be repaired as soon as crews, equipment, and/or corrective dispatch actions can be put in place to allow the work to be performed.

Participants should submit requests for emergency outages of transmission facilities immediately to the System Operator.

Operating Procedure No. 4

4 ACTION DURING A CAPACITY DEFICIENCY

4.1 Introduction

4.1.1 This procedure establishes criteria and guides for actions during capacity deficiencies, as directed by the System Operator and as implemented by the System Operator. This procedure may be implemented any time one or more of the following events, or other similar events, occur or are expected to occur:

- Moldova available power resources are insufficient to meet the anticipated load plus any operating reserve requirements.
- Transmission facilities into a subarea of Moldova power system are loaded beyond established transfer capabilities.
- A subarea of Moldova power system is experiencing abnormal voltage and/or reactive conditions.

4.2 Procedure

4.2.1 The System Operator will alert the participants promptly any time one or more of the above conditions are anticipated, or have actually been experienced. The alert will be issued. Upon implementation, the System Operator will notify the participants of the actions required. The actions will be initiated according to this document. The System Operator may dispatch power resources as required to ensure reliability.

(The actions will be developed in the future)

4.3 Cancellation of Actions

4.3.1 When the system conditions have improved sufficiently, the System Operator will cancel the instituted actions.

4.4 Communications with Participants

4.4.1 The System Operator control room staff will use the "party line" telephone circuit to implement this procedure. The System Operator will briefly inform all participants simultaneously of system conditions and issue an implementation message.

Operating Procedure No. 5

5 GENERATION MAINTENANCE AND OUTAGE SCHEDULING

5.1 Introduction

5.1.1 All generating units are to be maintained in accordance with good maintenance practices. To the extent possible, maintenance and outage requirements should be met by planning to prevent forced outages and by coordinating known outage requirements through the System Operator. Units should not be operated without maintenance to the extent that they are forced out of service and then maintained.

5.1.2 All generator maintenance and economic outages are to be scheduled according to this procedure. Generating units should not be taken out of service for maintenance without System Operator approval, unless there is danger to personnel or risk of equipment damage. If a generating unit is forced out of service due to personnel or equipment risk, the System Operator generation coordinator/forecaster and control room must be notified as soon as practicable.

5.1.3 This procedure defines the process for requesting, evaluating, and either approving or denying generator unit maintenance and economic outages.

5.1.4 The four maintenance outage-scheduling processes are:

1. The First Future Year - Maintenance and Outage Schedule
2. The Current Year - Maintenance and Outage Schedule
3. The Outage Request
4. The Short Notice Outage Request

5.1.5 This procedure is designed to facilitate each Participant's maintenance and outage scheduling.

5.1.6 The scheduling requirements are designed to allow

a) sufficient time for Participants to respond to the market's needs, and
b) sufficient time for System Operator to assess the impact of each generator's outage request on Moldova's bulk power system reliability.

5.1.7 This procedure includes definitions of key terms, responsibilities of Participants, System Operator, as well as rules for outage evaluation.

5.2 Definitions

Planned Outage
Means an outage, which is scheduled in advance and is of predetermined duration, usually lasting for several weeks, and typically occurs once or twice per year. These outages are initially coordinated in the First Future Year - Maintenance and Outage Schedule.

Maintenance Outage
Means an outage, which can be deferred beyond the 15 day window for short notice outage requests, but requires that the unit be removed from service before the next Planned Outage.

These outages are generally coordinated in the Current Year - Maintenance and Outage Schedule.

Short Notice Outage
Means an outage requiring the removal of a unit from service within the next 15 days and whose duration is less than 15 days. These outages are coordinated through the Short Notice Outage. Request.

Forced Outage
Means an unanticipated outage that requires the removal of a unit from service either immediately or with relatively short notice, due to unexpected maintenance where lack of attention could cause danger to personnel or risk of equipment damage. These unplanned outages do not require a Short Notice Outage Request. A Forced Outage does require the notification of the System Operator Generation Coordinator/Forecaster and the control room as soon as practicable.

Economic Outage
Means the removal of a unit from service for economic reasons based on a Participant's request consistent with Market Rules and Procedures. Participants may make decisions affecting the availability of a unit for reasons relating to the economics of operating that unit. Participants are expected to act in accordance with the applicable provisions of the Market Rules and Procedures, which provide for the coordination required to minimize the impact of unit unavailability on short term system reliability. These outages shall be coordinated through the Short Notice Outage Request, but these requests cannot be made more than seven (7) days in advance of such outage.

First Future Year - Maintenance and Outage Schedule
The First Future Year –Maintenance and Outage Schedule is published on or about each March 1 and covers generator outages scheduled for the next calendar year, known as the first future year. This schedule is intended to provide Participants and the System Operator sufficient lead-time to schedule all known, Planned Outages for the next calendar year. Updates to this schedule are made on a quarterly basis throughout the current year. The December update forms the basis for the January release of the Current Year –Maintenance and Outage Schedule.

Current Year - Maintenance and Outage Schedule
This cycle begins on January 1"' and covers the outages scheduled from the current publication date to the end of the current calendar year. Updates are provided on a monthly basis in the Current Year - Maintenance and Outage Schedule.

Outage Request
Outage Request is defined as a request to the System Operator by a Participant for a generator planned or maintenance outage with more than 15 days notification from the start of the outage. This request may be for outage duration changes, additions, deletions, repositions, or a new request.

Short Notice Outage Request
A Short Notice Outage Request is defined as a request to the System Operator by a Participant for a generator short notice outage with less than 15 days notification, from the start of the outage. This request may be for outage duration changes, additions, deletions, repositioning, or a new request. Economic outages are submitted using a Short Notice Outage Request, but an economic outage cannot be submitted more than seven (7) days in advance of the start of such outage.

5.3 System Operator Responsibilities

5.3.1 Evaluation Principles

The System Operator shall evaluate, all generator outage requests submitted by Participants for their impact on system reliability. Outages of an interconnection facilities will be included as part of this evaluation.
The purpose of System Operator's evaluation is to identify if generator outages cause either a
Transmission Criteria Violation or result in a negative Operable Capacity margin.
The System Operator will assign each outage request a tracking number upon receipt. Each request will be time and date stamped for prioritization purposes, and evaluated on first come first served basis.

5.3.2 Outage Request Approval Principles

Participants must receive System Operator's approval to remove a generating unit from service for a planned, maintenance, short notice or economic outage.
The System Operator will approve all generation planned, maintenance, short notice and economic outage.

5.3.3 The System Operator shall prioritize outage requests in the following order:

1. Forced Outages
2. All outages on the Current Year - Maintenance and Outage Schedule.
3. Outage requests approved since the last Current Year - Maintenance and Outage Schedule was distributed.
4. Short notice outages
5. Economic outages and all other maintenance requests will be given the lowest priority and processed on a first come first served basis.

5.4 First Future Year - Maintenance and Outage Schedule

5.4.1 First Future Year Outage Request Processing

The System Operator will respond to a Participant's First Future Year Outage Request for an outage duration change, addition, deletion, and repositioning as follows:

1. The System Operator will attempt to locate, within the outage commencement window supplied by the Participant, an acceptable period for the requested outage.
2. The System Operator will notify the Participant if the request is approved as submitted, or approved with modifications.

For First Future Year - Maintenance and Outage Scheduling requests, the System Operator will process generator outage requests as promptly as possible, and at the 1st, in time for the next quarterly publication.

5.4.2 First Future Year System Operator Reporting

The System Operator will publish the First Future Year - Maintenance and Outage Schedule on or about March 1, June 1, September 1 and December 1.
This process provides the Participants with a planning tool for reviewing their maintenance requirements and timing, and comparing that timing with the needs of the Control Area. This process provides the System Operator with a method for coordinating unit maintenance requirements to minimize the impact of unit unavailability on system reliability, and as a result, the System Operator can identify potential capacity deficient periods.

5.4.3 First Future Year Resolving Reliability and Security Violations

The System Operator will work with the Participants to reposition scheduled generation planned and maintenance outages the First Future Year - Maintenance and Outage Schedule.
The System Operator shall request that all parties either voluntarily reposition their requested outage or provide the System Operator with alternatives for repositioning their outage. System Operator shall specify the time Participants have to respond to this request.
In making its determination, the System Operator will group the requests by time stamp period, and then apply an allocation method. The method will be based upon each parties total generating capability compared to the sum of the requesting parties total generating capability. Previously approved outage requests will not be subjected to the allocation process.

5.5 Current Year - Maintenance and Outage Schedule

(To be developed similar way as previous one)

5.6 Short Notice Outage Request

(To be developed similar way as previous one)

5.7 Participant Responsibility

5.7.1 Information Requirements

Participants must schedule generator planned, maintenance, short notice and economic outages in accordance with this procedure and must provide all information required by this procedure, in the time frames indicated. Participants must submit all generator planned, maintenance, short notice and economic outage requests in accordance with this procedure. When submitting a generator outage request for either the current year or first future year, Participants must provide the following information for each request:

1. Name of Unit or Station
2. Amount of reduction

3. Preferred outage start date and time
4. Projected outage end date and time
5. Duration of outage (weeks and/or days)
6. Desired season for outage placement
7. Description of work to be accomplished during the outage
8. Information Submittal Process

5.7.2 Short Notice Outage Request Information:

Submit to the System Operator Generation Coordinator/Forecaster. Submissions by telephone.

Typical Outage Start and Ending Times
Expected To Be Available
Unit Type
Beginning Time
End Time
The unit is expected to return to service

5.7.3 System Operator Approval

Prior to removing a unit from service, Participants must obtain System Operator control room approval for all requests for generation planned maintenance, short notice and economic outages. System Operator will inform the appropriate Satellite when the unit is starting down and offline.

Operating Procedure No. 6

6 MOLDOVA POWER SYSTEM RESTORATION

6.1 Introduction

6.1.1 This procedure addresses restoration of the Moldova power system (110 kV and above) after a partial or complete system blackout. Expeditious restoration of the Moldova power system depends on independent actions and interactions by Participants and the System Operator. Depending on the expanse of the blackout (local area or widespread) numerous Participant restoration procedures, and this procedure, may need to be implemented simultaneously.

6.1.2 Technical aspects of system restoration (i.e. unit startups, load pickups, switching surges, voltages, frequency, synchronization of islands, etc.) will be crucial. Recognizing these concerns, this procedure and Participant restoration procedure have been developed in a coordinated fashion. This document:

- Outlines the responsibilities of the System Operator
- Provides technical guidelines for the restoration of transmission and generation facilities.

6.2 Moldtranselectro (System Operator)

6.2.1 Determine the extent of the blackout throughout Moldova power system and adjacent power systems (south –Ukraine adjustment; satellites connected to Romania) and inform all Participants of existing generation and transmission capabilities

6.2.2 Implement the System Operator restoration procedure (including necessary coordination with the Participants and adjacent power systems).

6.2.3 System Operator assign a loader to direct the startup and loading of units. The loader must ensure that:

- The technical guidelines which relate to unit startups, synchronization and loading are followed and,
- Unit operations are closely coordinated with switching operations.

Once the system is sufficiently restored and interconnected, unit dispatch will be resumed by the System Operator.

6.2.4 Assign a restoration coordinator to perform the following duties:

a) Establish communications with restoration coordinators in the participants' territories and adjacent power systems and a flow of information that promotes coordinated system restoration.

b) Monitor, advise and help coordinate with the participants and adjacent power systems, the following:

Energizations of high voltage system circuits; Energizations of inter-connection ties; Unit startups, load pickups, generation reserves and load shedding within interconnected systems after tie connections has been established.

c) Maintain a record of the Moldova power system blackout and restoration.

d) Provide updates on the status of the Moldova power system to the participants and adjacent power systems.

6.2.5 Authorize the closing of interconnection transmission lines.

6.2.6 Once tie lines are energized, oversee and coordinate load pickups within the interconnected parties.

6.2.7 Select priority for start-up of power resources.

6.2.8 Direct load shedding, if necessary, to enable continued reliable restoration of interconnected participants or the closing of interconnection ties.

6.2.9 Monitor Moldova power system transmission and generation facilities and, as practical, take action to promote system reliability.

6.3 System Restoration Guidelines

6.3.1 The following lists guidelines regarding the technical aspects of system restoration. Recognizing the numerous scenarios of possible system blackouts (the expanse of the blackout and resources available for restoration), knowledge of these guidelines is important. They represent a general-purpose tool for system restoration.

6.3.2 Opening Circuit Breakers and Switches

System Operator and participants restoration procedures contain detailed instructions regarding the opening of circuit breakers and switches. In most cases, in-place substation procedures provide specific switching instructions to be followed in the event of a substation blackout. Some substations have equipment, which automatically switches into a desired post-blackout configuration.

In general, capacitors and customer loads will be opened and disconnected from the high voltage transmission system. Similarly, circuit breakers or switches on the high voltage kV transmission system will be opened. On the transmission lines with voltage higher than 110 kV, step-down transformers will be opened on the high side to avoid the simultaneous energizations of a circuit for voltage higher than 110 kV along with a step-down transformer. Step-down transformers off the 110 kV system will be opened on either the high or low side.

Participants operators should have station and distribution capacitors opened in locations where customer load can effectively absorb charging from transmission lines. This will help prevent high voltage conditions on the transmission system and excessive under excitation on generators. Along these lines, operators should anticipate the use of any available reactors to help absorb charging and prevent high voltage.

6.3.3 Reviewing Load Tap Changer (LTC) Positions

During system collapse, LTCs on autotransformers could move toward/to extreme tap positions. For example, if a gradual voltage collapse occurs (over several minutes), LTCs could move to full boost positions in an attempt to maintain subtransmission or distribution voltage. Upon collapse, the LTCs would remain in these positions and subsequent reenergization of the autotransformers could result in excessively high voltages on the low side systems that could result in equipment or load damage.

Consequently, LTC positions should be checked prior to energizations of autotransformers. If LTC positions are substantially off nominal, taps should be moved to nominal positions before energizing autotransformers.

6.3.4 Generator Start Ups and MW Loadings

During system restoration, generator MW loadings will be primarily dictated by minimum MW loading requirements to ensure unit stability and the need to provide station service power to units without black start capability. Operators at generating stations should, in concert with System Operator and participants operators, endeavor to start as many units as possible. More units mean stronger sources in terms of synchronized inertia and control of frequency and voltage.

Stronger sources will also afford more circuit energizations, unit start-ups, spinning reserve, and load pickups (including larger block sizes of load pickups).

Once initial units have been brought on line and synchronized, they should pick up some/all the minimum load requirements for other units just prior to their startup/synchronization. Once these units start and synchronize, their minimum load requirements should be transferred to them by adjusting unit loadings in the synchronized subsystem. This method of providing minimum load requirements to units is generally preferable to doing load pickups after a unit has been synchronized.

6.3.5 Spinning Reserves

Initially, when few units are on-line, System Operator operators will not have many options regarding spinning reserves. As restoration progresses and more units are phased in, operators should establish and maintain enough spinning reserve to cover loss of the unit generating the most MW. Eventually, spinning MW reserves should be adequate to cover loss of the largest generating unit and have additional reserve for continuing unit start-up demands.

6.3.6 Load Pickups

Load Block Sizes

In general, pick up loads in block sizes that do not exceed 5% of total synchronized generating capability. One exception to this would involve initial phases of restoration where a large unit with slow governor response is synchronized to a small unit with fast governor response. To avoid overloading the smaller unit after load pickup, block sizes should be restricted to 5% of the smaller unit's MVA capability until (an) additional unit(s) is/are synchronized.

Frequency Increase Prior to Load Pick up, Automatic Underfrequency Load Shedding

Large frequency excursions are to be expected during system restoration and other subsequent cascading problems, operators should employ the following methods.

During initial stages of system restoration the block sizes of load pickups are most likely to be at/near the general limit of 5% of synchronized generation capability and large frequency excursions are most probable. Operators can compensate for the frequency dips by first increasing frequency to as high as 50.3 hertz prior to load pickup.

As system size grows and the ratio of load block sizes to synchronized generation decreases, smaller increases in frequency prior to load pickup will become appropriate.

Finally, as system sizes reach close to full load, load block sizes should become a small percent of synchronized generation and increasing/maintaining frequency after rather than prior to load pickups should be sufficient.

During restoration, operators should observe analog/instantaneous recordings of frequency response to actual load pickups (if available) and tailor their frequency increases and load block sizes to prevent excessive frequency excursions.

6.3.7 Cold Load Pickup

During system restoration, operators will be restoring feeder loads that have been deenergized for unusually long periods of time (commonly referred to as "cold load"). The longer the deenergization period, the greater the loss of typical on/off cycling and other types of diversity in the load. Upon reenergization of the load, simultaneous full demands of all the various load components can be encountered. Consequently, operators should anticipate cold load pickups that are 1.5 - 3 times greater than normal feeder loads. Also, the longer the deenergization period, the longer it will take for the cold load magnitude to decay to a more typical value. After performing several load pickups, operators should get a better feel of cold versus typical feeder loads.

6.3.8 Salient Electrical Concerns During System Restoration

Reliable frequency and voltage performance (both transient and steady state) and reliable circuit energizations are major concerns during system restoration, especially during initial stages. The following general guidelines address these concerns.

Transmission Line Charging
Anticipate the introduction of shunt MVAR charging from line energizations and ensure that adequate reactive control exists prior to line energizations. The following are typical charging values: .88 MVAR/mile for 330 kV, and .07 MVAR/mile for 110 kV. These figures show charging to be a critical concern on the 330 kV but much less of a concern on the 110 kV.

Voltage Schedules at Generators
Generating stations should work to maintain voltage schedules below normal levels during system restoration. This will help combat shunt MVAR charging from lightly loaded transmission lines and consequential high voltage and excessive switching surges. Lower voltage schedules will reduce transmission line MVAR charging (which is a function of voltage squared) and promote leading operation of generators and thus the absorption of transmission line MVAR charging. As system load size increases and significant real power MW flows start to occur on transmission circuits, normal voltage schedules at generating stations may become preferable. In any case, decisions on voltage schedules should be based on actual system voltage levels and leading reactive power limits on generators. If a unit is at/near its leading reactive power limit, other options for absorbing reactive power or reducing the amount of

reactive power that has to be absorbed should be exercised to restore leading reactive reserve on generators.

Circuit Energizations

Perform circuit energizations in a deliberate manner, checking the status of all associated facilities before and after energization. Synchronism, reactive conditions, and switching surges should be considered. In general, excessive switching surges are not anticipated for energizations on the 110 kV.

In the early stages of system restoration, 330 kV line or 330/110 kV transformer energizations should be done with a source that is electrically close to the energization, and has a large capability. As restoration progresses and the total capability of synchronized sources builds up the possibility of excessive switching surges decreases substantially.

The simultaneous energization of a 330 kV transmission line and a 330 kV step-down transformer should be avoided. In cases where this is not possible (no breaker between the line and transformer), the energization of these circuits should be done with a strong nearby source or in later stages of system restoration when sources are strong.

In general, a reactor connected to the tertiaries of 330 kV step-down transformers should be closed-in prior to energization of the transformers. This will help prevent excessively high switching and steady state voltages. Prior to switching, operators should confirm that the reactor will be beneficial, and be able to be supported after switching. In cases where multiple reactors are available, operators should decide how many reactors can/should be energized along with the 330 kV transformer.

If upon energization, a circuit immediately trips out due to relay protection, operators should try to have the lightning arrestors at the terminals of the circuit visually inspected for damage before making another attempt to energize the circuit. If inspection is not possible/timely, parties should be aware of and accept an increased risk for equipment damage during subsequent attempts to energize the circuit and other nearby circuits. The transmission equipment of most concern would be autotransformers.

Synchronizations

Generating stations are the preferred locations for synchronizing units, islands or systems together. These stations have synchronizing equipment, which is needed for regular unit phasing. Also, station operators are well versed in synchronizing techniques. In the restoration procedures, some synchronizations are planned at transmission (vs. generating) stations. For these cases, the necessary synchronizing equipment, operator knowledge and communication links to predefined generating stations (to match frequency) have been considered.

6.3.9 Inter-System Ties

The synchronization/energization of inter-pool ties should occur during fairly early stages of system restoration. This would minimize problems associated with trying to match frequencies of these pools. It would also promote the most effective use of available resources to restore the system in the least amount of time. However, the lack of direct control over switching operations in other pools and their overall status/reliability should be considered before establishing ties

Operating Procedure No. 7

7 ACTION IN AN EMERGENCY

7.1 Introduction

7.1.1 This document establishes procedures to be followed in the event of an operating emergency involving unusually low frequency, equipment overload or unacceptable voltage levels in Moldova power system. The objectives in establishing these emergency procedures are:

1. To minimize the effect on customer service.
2. To restore the balance between customers' load and available generation in the shortest practicable time.
3. To minimize the risk of damage to transmission and generating equipment, to distribution equipment and to customers' equipment.

7.2 System Operator Responsibility

7.2.1 The System Operator has the responsibility and authority to direct the actions that may be required for the implementation of this procedure, such as load shedding or opening of circuits, when the emergency situation involves:

A. An overall capacity deficiency within Moldova power system.

B. Moldova's interconnections with adjacent Ukraine system and/or Romania system.

C. Conditions on facilities external to Moldova power system caused by operations or conditions within the Moldova power system control area.

D. Transmission and/or generating facilities within Moldova.

7.3 Procedure

7.3.1 Preparation For Implementation

Normally, the potential need for emergency actions prescribed by this procedure should be determined well in advance of the time the actions must be implemented. This procedure may be implemented either before, during, or after action taken under Operating Procedure No. 4 - Action during a capacity deficiency depending on the circumstances of the emergency. However, Operating Procedure No. 4 will normally precede implementation of this procedure.

When system conditions indicate that implementation of this procedure may be required, the System Operator and the participants will establish and, if appropriate, maintain continuous communication in preparation for a System Operator directive to implement the procedure. Prompt action may provide time to be more selective in the application of this procedure.

If any participant and the System Operator are unable to establish prompt communication, the participant will proceed to implement the procedure independently.

When time and circumstances allow, the System Operator and the participants shall discuss the emergency conditions and reach consensus on the actions to be taken and the timing of those actions.

When operating circumstances do not allow time for consensus decisions, the System Operator and/or the participant will initiate the necessary actions prescribed by this procedure with the understanding that actions resulting in the higher level of reliability will be taken.

7.3.2 Procedures for Low Frequency Conditions

In an emergency characterized by a frequency drop, identification of the deficient area or areas is vital to expedite corrective action. The System Operator control room staff shall establish communications with other interconnected areas, as follows, to determine, if possible, the cause of the frequency decline and the action required to restore frequency to 50.00 Hz.

A. When the cause of the declining frequency is outside of Moldova:

- Confirm existing interchange schedules with adjacent Ukraine and/or Romania areas.
- Regulate the Moldova ties to maintain the frequency-biased interchange schedules.
- Increase the amount of synchronized reserve to be able to adjust the interchange schedule further, if needed.
- Make known to external areas the amount of emergency capacity Moldova can make available.
- Actions described in Section B below may be implemented when external areas request assistance from the System Operator. Please note that some of these actions will occur automatically regardless of the area causing the frequency decline.

B. When the cause of the declining frequency is due to a deficiency in Moldova:

- Confirm existing interchange schedules with adjacent areas.
- Request assistance from external Areas up to the emergency transfer limit of the interconnection tie lines.
- When the frequency reaches **49.90** Hz order fast-start non-synchronized units into service as required.
- When the frequency reaches **49.80** Hz automatic generation control (AGC) will be tripped automatically.
- Direct all thermal generations to their high operating limits (HOL) at maximum response rates.
- When the frequency reaches **49.30** Hz underfrequency relays will provide 10% load relief. By the time the frequency reaches 49.00 Hz, confirm that this relief was provided.

- When the frequency reaches **48.80** Hz underfrequency relays will provide an additional 15% load relief. By the time frequency reaches 48.50 Hz, confirm that this relief was provided.
- If the load shedding by automatic underfrequency relays does not stabilize the frequency and it continues to decline below **48.50** Hz order manual load shedding.
- 50% of Moldova's load, including the 25% that is shed automatically, can be shed manually.
- All stations shall take the necessary action, including separating units from the system, to preserve generation and minimize damages and service interruptions.

7.3.3 Procedures for a Transmission Emergency

Operation of the transmission system under emergency conditions shall be governed by Operating Procedure No. 17 - Transmission Operations. Emergency actions, including the switching of transmission elements, implementing voltage reductions, and the shedding of firm load, can be taken by the System Operator and the participants to maintain reliability.

The System Operator and the participant operators are responsible to keep appropriate supervisors at the System Operator and the participants advised as to conditions that might necessitate management review of the need to implement emergency actions on a pre-contingency basis.

7.3.4 Procedures for Unacceptable Voltage Conditions

Operating Procedure No. 11 - Voltage and Reactive Control and various voltage guides define criteria and establish guides for action to be taken to insure that desirable levels of voltage are maintained on the transmission system. The participants control center shall make every effort to correct unacceptable voltage and shall coordinate actions with the System Operator.

When unacceptable voltage conditions occur and corrective actions described Operating Procedure No. 11 and/or the voltage guides are not effective, the System Operator control room staff and/or the participant operators should take emergency actions, as defined Operating Procedure No. 17 - Transmission Operations, to correct the situation.

The System Operator control room staff and participant operators are responsible to keep appropriate supervisors at the System Operator and the Participants advised as to conditions that might necessitate management review of the need to implement Emergency Actions on a pre-contingency basis.

7.3.5 Restoration of Load

The System Operator will direct the restoration of any load shed under this procedure when system conditions permit.

7.3.6 Instructions For Implementation Of Manual Load Shedding

The following instructions are to be observed by the System Operator Control Room Staff during the manual shedding of load.

All participants will be on the party line prior to the time the System Operator Control Room Staff issues instructions.

A. Quantity of Load

The System Operator Control Room Staff will direct the quantity of load to be shed or restored by specifying a step number.

$$\text{Step Number} = \frac{\text{Total MW Load to be Shed or Restored x 100}}{\text{Instantaneous Moldova Load}}$$

B. Instruction Messages

The System Operator Control Room Staff will issue concise verbal instructions and await participant acknowledgment, which should be received from all participants alphabetically. Typical messages are as follows:

Implementation:

System Operator to participants: Implement Operating Procedure No.7 - Manually shed load from step ____ through step _____.

System Operator to participants: Implement Operating Procedure No.7 - Manually restore load from step ____ through step _____.

Acknowledgment by participant:

_____________________, OP 7 - Manually shed load from step _____through step _____.

_____________________, OP 7 - Manually restore load from step _____ through step _____.

Operating Procedure No. 8

8 OPERATING RESERVE AND AUTOMATIC GENERATION CONTROL

8.1 Introduction

8.1.1 Operable capability in addition to the quantity required to meet the actual Moldova Power System load, is required to reliably operate the Moldova interconnected electric power system. Such additional capability, provides for:

1. Loss of generating equipment within the Moldova Power System.
2. Loss of transmission equipment within Moldova power system or between Moldova and Ukraine (and/or Romania) that might result in a reduction of energy transfer capability within Moldova power system.
3. Automatic Generation Control (AGC) in the Moldova power system (future).
4. Errors in forecasting Moldova loads.

8.1.2 This procedure sets forth criteria for the establishment and administration of Operating Reserve and AGC in the Moldova power system.

8.1.3 The objective is to ensure that Moldova's power resource system is operated at the prescribed level of reliability.

8.2 Definitions

8.2.1 To ensure mutual understanding, terms used throughout this procedure are synonymous with definitions contained in the Power Market Rules.

Operable Capability
The high operating limit of a resource, such as a generator, contract, dispatchable or interruptible load, etc.
Synchronized Reserve Capability
The unused portion of operable capability which is synchronized to the system and ready to pick up load and the capability that can be made available by curtailing dispatchable loads.
Nonsynchronized Reserve Capability
That portion of operable capability that is available for synchronizing to the system plus the capability made available by the curtailment of interruptible loads. Other load relief management techniques, such as voltage reduction load relief available within ten minutes, may be counted as nonsynchronized reserve after implementation of Operating Procedure No. 4 - Action during a Capacity Deficiency.
Operating Reserve
The sum of synchronized and nonsynchronized Reserve.

Automatic Generation Control (AGC)
A measure of the ability of a generator or portion thereof to respond automatically within a specified time to a remote direction from the System Operator to increase or decrease the level of output in order to control frequency and to maintain currently proper power flows into and out of the Moldtranselectro power system.

Reportable Events
System disturbances involving losses of load, generation, or transmission facilities, which equal or exceed the following criteria, are reportable events:

- Actual net (interchange) tie line flow deviations equal to or greater than xxx MW.
- Loss of generation or load equal to or greater than xxx MW.
- System frequency deviations equal to or greater than 0.03 Hz.

8.3 Operating Reserve Distribution

8.3.1 Operating Reserve shall be distributed to ensure that it can be fully utilized System Operator for any probable contingency without exceeding transmission system limitations and to ensure operation in accordance with operating procedures.

8.4 Operating Reserve Restrictions

8.4.1 When allocating operating reserve to the various resources, particular attention must be given to temporary limitations and deratings. Only that capability that can actually supply MW in the applicable period shall be classified as operating reserve.

8.4.2 It is recognized that units called upon to activate reserve will operate without relief until the System Operator determines they are no longer needed.

8.5 Shortage f Operating Reserve

Operating Reserve will be provided to prescribed levels of synchronized and non-synchronized reserve from within Ukraine. If available capability is insufficient to provide adequate operating reserve, System Operator will implement the various Actions of Operating Procedure No. 4.

8.6 Testing Of Thermal Unit Response Rates

8.6.1 As outlined in Power Market Rules System Operator has the responsibility to conduct tests of the response rates. The ability of internal combustion units to start and demonstrate operating reserve capability shall be tested at regular intervals. System Operator will attempt to coordinate these tests with system conditions and participants' normal testing practices.

8.7 Responsibility

8.7.1 System Operator is responsible for operating the Moldova power system in accordance with established criteria. This includes the responsibility for determining when operating reserve above minimum levels prescribed will be retained. Further, System Operator is responsible for determining how best to meet AGC and tie line response criteria.

8.7.2 System Operator is also responsible for for determining the required amount of operating reserve; for specifying the type, location, and quantity to be maintained; for selecting the number of units as well as the location of units to be assigned to AGC; for communicating the directive to units for activating operating reserve in response to contingencies in Moldova power system.

8.7.3 Participants are responsible for communicating to System Operator current system conditions affecting operating reserve. The participants are also responsible for activating operating reserve for localized problems within a local area when time does not permit communication with System Operator.

Operating Procedure No. 9

9 SCHEDULING AND DISPATCHING OF EXTERNAL CONTRACTS

9.1 Introduction

9.1.1 This procedure describes the actions that the System Operator must perform, with respect to power system scheduling and dispatch, in order to implement external contracts. Information regarding each external contract and its implementation parameters must be submitted to System Operator in accordance with Market Rules and Procedures. Any external contract for which incomplete information is submitted will not be accepted by System Operator for implementation. System Operator will verify all transmission arrangements related to external contracts and the adequacy of contract information submittal.

9.1.2 A specified through or out service rate is charged for transmission service. Through or out service as it applies to out transactions is point-to-point transmission service provided to an participant by high voltage service

9.1.3 Any other transmission service that is required from a transmission provider internal or external to Moldova must be obtained by a party to the transaction, and must be obtained through OASIS from the transmission provider or from its designated tariff administrator. Such service must be obtained prior to the time that the System Operator is requested to implement any transaction that is dependent on that transmission service.

9.2 Transmission Restrictions

9.2.1 Transmission restrictions imposed by an external transmission provider or its Control Area Operating Authority will be accepted and applied by System Operator. The restrictions will be reflected in the schedule and availability data that will be sent to System Operator Settlements for processing according to Market Rules and Procedures.

9.3 General Information

9.3.1 The System Operator scheduling office will validate contract submittals in order of submission.

9.3.2 After verifying that appropriate transmission arrangements are in place, the contract information submittal is complete, and that external Control Area involved have a record of the transaction, the System Operator will implement the external contract in accordance with the requested schedule, unless system reliability considerations require an adjustment to the requested schedule or prevent such implementation altogether.

9.4 Through Transactions

9.4.1 The System Operator scheduling office will verify that appropriate and adequate transmission arrangements are in place with respect to the use of transmission system prior to implementing a through transaction.

9.4.2 Through transactions do not affect System Operator's power dispatch activities. Such a contract may affect System Operator's power dispatch to the extent that it results in congestion on a transmission interface internal to Moldova's Control Area.

9.5 Check out with Neighboring Control Areas

9.5.1 The System Operator scheduling office will perform the day ahead check out by transaction of energy scheduled with the neighboring Control Areas to develop the preliminary interchange. The System Operator will perform the real time check out with the neighboring Control Areas.

9.6 Curtailment of External Contracts

9.6.1 The System Operator will be prepared to curtail each and all of the external contracts that have been scheduled across if necessary to maintain system reliability.

9.6.2 Curtailment or interruption may be due to, but not limited to:

a) A limited set of specified pre-determined conditions,
b) Transmission restrictions (both internal and external),
c) Transmission interruption,
d) Other system reliability concerns.

9.7 Notifications

9.7.1 When an external contract for sale from an internal seller to an external purchaser must be curtailed, the System Operator will inform the scheduling office. The scheduling office will inform both parties as soon as possible after the System Operator becomes aware of the existence of conditions that prevent or restrict energy deliveries.

9.7.2 When an external seller or its Control Area Operating Authority informs the System Operator that a Moldova participant's purchase must be curtailed, the System Operator will notify the scheduling office. The scheduling office will advise the internal purchaser as soon as possible of the actual or pending curtailment and, to the extent of its knowledge, the reason for the curtailment and its expected duration.

9.8 Settlement Information

9.8.1 The schedule and availability data will be sent to Settlements Center for processing according to Market Rules and Procedures.

Operating Procedure No. 10

10 ANALYSIS AND REPORTING OF POWER SYSTEM EMERGENCIES

10.1 Introduction

10.1.1 Government and government agencies must be notified whenever abnormal operating conditions, such as those identified below, seriously degrade the reliability of the System Operator power system. The National Energy Regulatory Commission (ANRE) and the participants must also be notified of system conditions or disturbances that impact the reliability of the Moldova power resources system.

10.1.2 This procedure establishes the reporting criteria, assigns reporting responsibility, and describes the nature and timing of the required reports for:

- Moldova Government (including Department of Energy)
- National Energy Regulatory Agency (ANRE)
- Participants
- The public

10.1.3 For the purpose of this procedure, the Moldova power resources system includes any generating unit and/or electric facility provided power supply to high voltage system.

10.1.4 The System Operator Emergency Communications Plan provides information about initial reporting responsibilities for a range of emergency conditions.

10.2 Government

This section describes the criteria for filing reports with the DoE. Reporting responsibilities and other requirements are also described.

10.2.1 Bulk Power Supply System Reporting Criteria

The Moldova Department of Energy's Office of Energy Emergencies (DoE) and ANRE requires that every electric utility engaged in the generation or transmission or distribution of electric energy report promptly to the DoE Emergency Operations Center events in any of the categories described below. System Operator’s Operating Procedures are referenced in parentheses where applicable.

The time frame for issuance of telephone reports is identified for each event category.

1. Loss of Firm System Loads

a) Any load shedding actions resulting in the reduction of over xxx megawatts (MW) of firm customer load for reasons of maintaining the continuity of the Moldova power resources system. (OP 7)

b) Equipment failures and system operational actions associated with the loss of firm system loads for a period in excess of 15 minutes, as described below:

- Reports from participants with a previous year recorded peak load of over xxx MW are required for all such losses of firm loads which total over xxx MW.

- Reports from all other participants are required for all such losses of firm loads which total over xxx MW or 50 percent of the system load being supplied immediately prior to the incident, whichever is less.

c) Other events or occurrences which result in a continuous interruption for 3 hours or longer to over xxx customers, or more than 50 percent of the total customers being served immediately prior to the interruption, whichever is less.

d) When to Report: The DoE Emergency Operations Center and ANRE shall be notified as soon as practicable without undue interference with service restoration and, in any event, within 3 hours after the beginning of the interruption.

2. Voltage Reductions and public appeals

a) A report is required for any anticipated or actual system voltage reductions of 3 percent or greater for purposes of maintaining the continuity of the Moldova power resources system. (OP 4)

b) A report is required for any issuance of a public appeal to reduce the use of electricity for purposes of maintaining the continuity of the bulk electric power system. (OP 4)

c) When to Report: The DOE Emergency Operations Center and ANRE shall be notified as soon as practicable, but no later than 24 hours after initiation of the actions described in this paragraph 2.

3. Vulnerabilities that could impact Moldova power system adequacy or reliability

a) Reports are required for any actual or suspected act(s) of physical sabotage (not vandalism) or terrorism directed at the Moldova power resources system in an attempt to:

   - Disrupt or degrade the adequacy or service reliability of the power system such that load reduction action(s) or special operating procedures may be needed.
   - Disrupt, degrade, or deny power service on an extended basis to a specific:
     (1) Facility (industrial, military, governmental, private),
     (2) Service (transportation, communications, country security), or
     (3) Locality (town, city, county).

   This requirement is intended to include any major event involving the supply of bulk power.

b) Reports are required for any other abnormal emergency system operating conditions or other events, which, in the opinion of the reporting entity, could constitute a hazard to maintaining the continuity of the Moldova power resources system. DoE and ANRE have a special interest in the actual or projected deterioration in power resources adequacy and reliability due to any causes. Events, which may result in, such deterioration include, but are not necessarily limited to: natural disasters; failure of a large generator or transformer; extended outage of a major transmission line or cable; Country actions with impacts on the power system.

c) When to Report: The DoE Emergency Operations Center and ANRE shall be notified as soon as practicable after the detection of any actual or suspected act(s) or event(s) directed at increasing the vulnerability of the bulk electric power system. A 24-hour maximum reporting period is specified in the regulations; however, expeditious reporting, especially of sabotage or suspected sabotage activities, is requested.

4. Fuel Supply Emergencies

a) Reports are required for any anticipated or existing fuel supply emergency situation which would threaten the continuity of the power resources system, such as:
   - Fuel stocks are at 50 percent or less of normal for that time of the year, and a continued downward trend is projected.
   - Unscheduled emergency generation is dispatched causing an abnormal use of a particular fuel type, such that the future supply or stocks of that fuel could reach a level, which threatens the reliability or adequacy of power resources.

b) *When to Report*: Fuel supply adequacy is a factor in the availability of generating resources. Conditions such as interruption of supply, limited storage or the above stated criteria may limit the dispatch availability of a participant's generating resource(s).

c) Participants shall notify System Operator when inadequate fuel supplies will limit the dispatch availability of their generating resources. The System Operator and the participant together shall determine if the resource availability will affect the reliability of the Moldova power system. If this limited availability shall affect the reliability of the power system, the participant will notify the DoE Emergency Operations Center and ANRE as soon as practicable, but no later than 3 days after the determination is made.

10.2.2 Government Reporting Procedures

1. Responsibility

a) The System Operator reports all reportable incidents under DoE and ANRE Power System Emergency Reporting Procedures, except:
   - When a participant indicates a desire to report an incident that affects only this participant.

b) System Operator is responsible for determining the need for reports covered by this operating procedure.

c) The System Operator manager - operations is responsible for proper notification to the DoE and ANRE. The manager - operations, or designee, will complete all required forms for any reportable event listed in Section II.A of this procedure.

d) It is the responsibility of all Participants to provide the System Operator with the necessary information to evaluate events covered by this procedure.

2. Telephone Reports

a) System Operator will make a telephone report to the DoE Emergency Operations Center and ANRE. An emergency coordinator in the DOE Emergency Operations Center will answer and the message will be recorded.

b) The telephone report must include the following information:
   - Type of report (interruption, voltage reduction, public appeal, vulnerability action or other hazard).

- Name of the participant and location of the main office and the area or the division in which the disturbance has occurred.
- Name, title, and telephone number of an individual who may be contacted for further information about this incident. The number should be one at which the person can be contacted within the next two hours. If the person's normal business phone is different, it should also be provided.
- Area(s) affected by the incident.
- Date, and time of the incident.
- Date, and time of initial and final service restoration.
- Estimated duration of the incident, if customer service and normal system operating conditions have not already been restored.
- Number of customers disconnected (estimate) or otherwise affected.
- MW load lost (estimate).
- Brief description of the incident.

3. Written Reports
   Written reports are required only when specifically requested by DoE and ANRE. The form may be faxed or sent to DoE, Office of Energy Emergency Operations and ANRE.
4. Full Technical Reports
   The DoE and ANRE, may require a participant that experiences a condition described in Section A of this procedure to prepare a full technical report of the technical circumstances surrounding the incident, including the restoration procedures utilized.
   The System Operator and the Participant(s) will jointly prepare the full technical report.

10.3 System Operator Analysis and Reporting Requirements

10.3.1 The interconnected bulk power system is being operated at an ever-increasing capacity factor. This increased duty has resulted in greater power system sensitivity to faults, losses of equipment, and/or equipment malfunctions. Accordingly, it is essential that power system behavior, during periods immediately following abnormal operations, be carefully analyzed. These operations include not only severe system disturbances, but also incidents that fall into the "near miss" or abnormal (versus emergency) category.

10.3.2 This section of the procedure establishes the responsibility for analysis of abnormal events and reporting to Participants as required for assuring the reliability of the Moldova power system. The reports resulting from these analyses may also be used to fulfill the reporting requirements of the Department of Energy (DOE) and ANRE.

10.4 Events Requiring Analysis And Reports

10.4.1 The following types of events are "triggers" for System Operator to conduct an analysis and prepare a report:

1. Incidents that are reported to the DOE and ANRE
2. Incidents involving a successful or unsuccessful operation of a special relay protection system

3. Other incidents that warrant review and reports. These include, but are not limited to:
   - Prolonged (sustained) oscillations
   - Severe voltage excursions
   - Multiple and simultaneous loss of generators and/or transmission system elements
   - Loss of significant customer load

10.4.2 Reporting Procedures

1. Responsibilities
   a) The System Operator has the responsibility for the determination of the need for analysis and reports of power system incidents covered by this procedure. The severity of the incident determines the depth of the analysis and the type of report (brief and general or lengthy and detailed).
   b) Staff representing System Operator and participants has the responsibility for conducting the analysis and preparation of subsequent reports. The particular power system incident will normally determine the make-up of the group assigned to review an incident. The affected participants will always be involved in the review of an incident. Lead responsibility may be assigned to System Operator or a participant.
2. Time Schedule for Reports
   c) The time schedule will meet DoE and/or ANRE time requirements.
3. Contents of Final Report
   d) The Final Report will include information that is available within thirty (30) days of the incident. If additional information is developed after the thirty (30) day period, a follow-up report will be issued upon the completion of the investigation.
   e) Final reports will include comments pertaining to the following:
      - Dates and times of events
      - Executive summary of analysis
      - Pre-incident power system conditions (weather, load, generation patterns, outages of generation and transmission prior to incident, inter-participant transfers, frequency schedules, key bus voltages)
      - Immediate post incident power system conditions (similar to pre-incident items)
      - Amounts of load/generation lost
      - Items peculiar to particular incidents:
        - Relay operations - correct; correct but undesirable; incorrect
        - Damaged equipment
        - Causes
        - Injuries
        - Reliability of system (pre; post)
        - Comparison of actual behavior and simulation
        - Violations of established procedures and rules, instructions, etc.
        - Lessons to be learned
        - Recommendations

- Action Items:
    - Participants
    - System Operator

4. Final Report Distribution

   The DoE and ANRE will authorize distributions as determined by the nature of the incident.

10.5 Public Notification

The System Operator manager for affairs and public information is responsible for all communications with the media and news organizations.

Operating Procedure No. 11

11 **BLACK** START CAPABILITY TESTING

11.1 Introduction

11.1.1 An integral portion of any system restoration is the provision of units with black start capability. By definition, a black start unit is capable of being started without energy from another Moldova system or toher generating unit. Units claiming black start capability should strive to achieve the fastest start time possible within a two-hour time frame. Once started, black start units begin the process of starting and synchronizing other units without black start capability and, energizing and synchronizing transmission. This procedure outlines requirements for testing black start capability. These tests will provide training for power plant operators, and provide the System Operator and the participants with up-to-date information concerning the black start process for system restoration.

11.1.2 The process of starting black start units, establishing system configurations which will allow the energizing of transmission circuits to units without black start capability, and the subsequent synchronizing of these unit(s), is the basis of Operating Procedure No. 6 - System Restoration. Therefore, it is prudent to test the black start capability of each black start unit in preparation for the possibility of a system restoration. In addition the System Operator and the participants should test other emergency procedures, such as load shed simulation and voltage reduction tests, on a regular basis.

11.2 Testing

11.2.1 All generating stations equipped with black start capability will perform an actual black start of the unit without dependency on the interconnected system or other unrelated unit support. Participants may also choose to conduct black start tests as part of their scheduled inspection.

11.2.2 Tests should include key operating aids used in black starts such as telephone communications and SCADA, if applicable. The time required for the test should include start-up of the unit plus station's service switching time to the actual synchronizing of the unit. Prior to beginning the black start test, station personnel shall notify the System Operator, and receive approval in cases where the test will delay the planned start-up or shutdown time of the unit or other units.

11.3 Scheduling

11.3.1 Recognizing that each black start unit has unique complexities involved in start-up, some scheduling flexibility must be allowed in minimum requirements of scheduling tests. For instance, testing of some units may require interruption of firm customer load, which could be unacceptable. Whereas, other units can black start at anytime and require little, if any, planning. All units available for black start that do not impact firm customer load must test this capability at least once every three year period at the participant's convenience. These tests will be coordinated with the System Operator forecast department. Participants who plan their tests during a scheduled inspection should schedule this through the System Operator generator maintenance scheduler.

11.4 Reporting

11.4.1 Many participants already have a black start test procedure in place and would simply require filing the report on these tests with the System Operator. Those participants who do not currently test black start capability will file a letter with the System Operator on the success or failure of the test, including any problems that were encountered and remedial actions, if any, needed to correct the problem. The System Operator will compile the results of the tests and publish an annual black start report to inform all participants.

Operating Procedure No. 12

12 VOLTAGE AND REACTIVE CONTROL

12.1 Introduction

12.1.1 This procedure provides broad criteria, operating practices and responsibilities to help ensure that desired/reliable voltage and reactive conditions are maintained on the power system. It also includes general actions to control voltage/reactive conditions when deviations from normal occur or are needed to minimize adverse effects during abnormal conditions.

12.1.2 More specific criteria and actions may be required when the measures described in this procedure do not correct the abnormal voltage/reactive conditions. This information will be contained in more detailed documents issued by the System Operator.

12.2 VOLTAGE SCHEDULES AND LIMITS FOR GENERATORS AND KEY TRANSMISSION STATIONS

12.2.1 Major generating stations throughout Moldova should have specified voltage schedules, which should be maintained as closely as possible in system operations. They should also be used by operators and planners in off-line studies of the power system. During certain conditions at a generating station or on the power system, sustained deviations from voltage schedules may be required/unavoidable and minimum and maximum voltages have been established that can be sustained at generating stations during these infrequent conditions.

12.2.2 In addition to voltage schedules, minimum and maximum voltage limits at several key generating or transmission stations should be established to promote system reliability during adverse voltage/reactive conditions. These reliability concerns can be based on the security of the transmission system or station service supplies to nuclear generators.

12.3 Generator Reactive Capabilities, Commitments and Required Reactive Reserves

12.3.1 Generator reactive capabilities available to regulate voltages should be employed in system operations and analyses. Data collection methods have been designed such that these reactive capabilities should be fully available except for occasional times when unique temporary problems occur at a particular generating station.

12.3.2 To promote security of the transmission system during adverse voltage/reactive conditions, required unit commitments and levels of required reactive reserve for generators within Moldova Control Area. System conditions that warrant the prescribed unit commitments or reactive reserves should be identified.

12.4 Voltage/Reactive Operating Practices

12.4.1 Traditional Voltage/Reactive Control

Besides the use of generator reactive capabilities, the proper dispatch of shunt capacitors/reactors combined with effective transformer voltage schedules or fixed tap settings are the most traditional means of achieving desired voltages and reactive conditions. Listings of switchable shunt devices installed to support the Moldova Control Area transmission system (110 kV and above) and guides for switching them should be established.

12.4.2 Circuit Switching to Control High Voltage

In some areas, transmission circuit switching is a viable option for controlling high voltage/excessive charging conditions. The System Operator shall provide this information for switching circuits to control high voltage.

12.4.3 Load Management for Voltage/Reactive Reliability

In severe cases of low voltage and/or inadequate reactive reserves, load management actions can be taken. Details on conditions when these actions can/should be used and how they should be implemented.

12.5 Responsibilities

12.5.1 This procedure is based on the principle that voltage control is best achieved when action is taken as close as possible to the affected area. Voltage schedules and other reactive conditions will be supervised by the System Operator operators, being responsible for an ever expanding area of responsibility.

12.5.2 Generating and Transmission Stations

Generating and transmission station operators are responsible for maintaining station service and other local voltage requirements and scheduled voltages at levels designated by individual Participants. Generating stations are also responsible for maintaining voltage schedules set for the high side of the generator step-up transformers. Normally, automatic voltage regulation works off the low side of the step-up transformer (generator terminals). Thus, in order to maintain a high side voltage schedule, manual intervention can be required to offset varying power flows through and voltage drops across the step-up transformer.

12.5.3 When unable to maintain scheduled station and local voltages with the means under their control, the generating station operators should notify the System Operator.

12.5.4 Participants

Participants are responsible for monitoring and supervising the following conditions within their territories:

- voltage schedules and limits,
- unit MVAR loadings, capabilities and reserves,
- shunt capacitor and reactor dispatches,
- transformer voltage schedules or fixed tap settings,
- synchronous condenser operation,
- Static VAR Compensator operation (must be coordinated with the System Operator),

- line switching for voltage/reactive control (must be coordinated with the System Operator and, if warranted, with participants),
- the Participants will notify/ coordinate the need for MW re-dispatch for MVAR requirements with the System Operator.
- other predefined indicators of voltage/reactive security (e.g. a particular circuit flow, the status of specific units, area load level, etc.).

Participants are responsible for:

1) detecting and correcting deviations from normal scheduled voltage/reactive operations,
2) responding to notifications by generating or transmission station operators of difficulty in maintaining station or other local voltage or reactive schedules and,
3) responding to System Operator requests to assist with area problems.

Participants are authorized to exercise the following actions to correct voltage/reactive difficulties within their territories:

- direct voltage schedules and levels of reactive output and reserve on generators, synchronous condensers and static VAR compensators,
- direct the use of shunt capacitors and reactors,

When a participant is unable to correct a voltage/reactive problem using the above the participant will notify the System Operator and request assistance.

12.6 System Operator

12.6.1 The System Operator is responsible for the general monitoring and supervision of voltage/reactive conditions on the Moldova power system. If in monitoring the system a problem is detected, the System Operator will request action.

12.6.2 The System Operator is also responsible for monitoring and supervising voltage/reactive operations of ties. Problems may be noticed by the System Operator or appear in the form of requests from neighboring pools or companies for assistance. The System Operator will inform the appropriate Participant(s) of the nature of the problem specifying, and general conditions aggravating the difficulty.

12.6.3 When abnormal voltage/reactive operating conditions materialize, the System Operator may initiate a survey of key system parameters to better assess the nature and expanse of the conditions.

Operating Procedure No. 13

13 STANDARDS FOR VOLTAGE REDUCTION AND LOAD SHEDDING CAPABILITY

13.1 Introduction

13.1.1 This document establishes standards for the installation and testing of participants with control over transmission/distribution facilities voltage reduction and load shedding capability. These standards require that all Moldova Participants – distribution companies or independent customers with control over transmission and/or distribution facilities have the capability to reduce load demand when directed to do so for power supply dispatching purposes. These load-reducing capabilities are used by the System Operator to maintain system reliability during generating capacity deficiencies, energy deficiencies, and other emergency operating conditions as described in Operating Procedure No.4 and Operating Procedure No.7.

13.2 Compliance

13.2.1 Participants with control over transmission/distribution facilities are expected to comply with the standards established by this Operating Procedure. Those not in compliance are expected to proceed immediately to achieve compliance. Arrangements may also be made for one participant with control over transmission and/or distribution facilities to provide voltage reduction and/or load shedding capability for another participant (customer) with control over transmission/distribution facilities during a portion of the day or week. Participants providing voltage reduction and/or load shedding capability for another participant with control over transmission/distribution facilities must not count the capability dedicated to another participant with control over transmission/distribution facilities toward meeting its own requirements. The details of arrangements between participants with control over transmission/distribution facilities for voltage reduction and/or load shedding services to meet the standards of this operating procedure must be submitted to and approved by System Operator.

13.3 Requirements

13.3.1 Voltage Reduction

a) Voltage reduction should take place on the distribution system wherever possible. It is recognized that in certain areas, voltage reduction is implemented on the subtransmission system. Voltage reduction should not be implemented on the transmission system operating at 110 kV and above.

b) Ideally, voltage reduction capability should be installed so that all loads are subject to a five-percent voltage reduction. However, it is recognized that it may not be practical to subject some loads to voltage reduction (e.g., loads served from the transmission system, voltage sensitive loads, etc.). It may be desirable to subject some loads to a voltage reduction of less than five percent.

However, each participant with control over transmission/distribution facilities must have the capability to reduce system load demand at the time a voltage reduction is initiated by at least one and one-half percent through implementation of a voltage reduction.

c) It is intended that voltage reductions be fully implemented within ten minutes from the time ordered. However, it is recognized that it may not be practical for some participants with control over transmission/distribution facilities to meet this requirement. In those circumstances, voltage reduction that can be implemented in thirty minutes is permissible.

d) Each participant with control over transmission/distribution facilities must be able to implement a voltage reduction on all non-holiday weekdays during the period between 0800 to 2300 hours.

13.3.2 Load Shedding

a) Each Participant with control over transmission/distribution facilities must install underfrequency load shedding equipment to accomplish the following in an emergency characterized by rapid frequency decline:
Automatic load shedding of ten percent of load initiated at a nominal set point of 49.3 Hertz.
Automatic load shedding of an additional fifteen percent of load initiated at a nominal set point of 48.8 Hertz.

b) These load shedding steps are designed to return frequency to at least 48.5 Hertz in ten seconds or less and to at least 49.5 Hertz in thirty seconds or less, for a generation deficiency of up to twenty-five percent of the load.

c) Load shed automatically by underfrequency relays shall not be automatically restored.

d) Each participant with control over transmission/distribution facilities must be capable of manually shedding at least fifty percent of load in ten minutes or less. Insofar as practical, the first half of the load shed manually should not include that load which is part of any automatic load shedding plan.

e) Manual load shedding should not interrupt transmission paths. Participants with control over transmission/distribution facilities who include such interruptions in load shedding plans must demonstrate from system simulations that transmission interruptions will not degrade interconnected system reliability.

f) The plan should include the capability of shedding load proportionately over the whole system; however, it is recognized that this may not be practical in some areas.

g) Generation connected to sub-transmission or distribution systems will have an ever-increasing impact on load shedding plans. If such a resource is interrupted as part of a participant with control over transmission/distribution facilities load shedding plan, an equivalent amount of additional load must be included in the load shedding plans.

h) Each participant with control over transmission/distribution facilities must be capable of implementing automatic and manual load shedding twenty-four hours a day.

13.3.3 Compliance Surveys

The System Operator will survey each participant with control over transmission/distribution facilities to verify voltage reduction and load shedding capability. Such surveys will be conducted at least once every two years and at most once each year. In addition, a new participant with control over transmission/distribution facilities will be required to complete a survey within 30 days after becoming a Participant.

13.4 Testing

13.4.1 Voltage Reduction

The System Operator will conduct system-wide voltage reduction tests. An actual voltage reduction will be implemented. Participants with control over transmission and/or distribution facilities will record the load reduction attained within ten minutes and/or thirty minutes in the test. Each participant with control over transmission/distribution facilities will complete a questionnaire that will record load relief attained and identify operational, or customer, problems that were encountered and should be resolved. The data will be used by the System Operator to update load relief estimates contained in Operating Procedure No. 4 - Action During a Capacity Deficiency, and to help verify each participant's with control over transmission/distribution facilities voltage reduction capability.
Voltage reduction tests will be conducted in accordance with the following parameters:

i) A date will be established for the test.

j) Participants with control over transmission/distribution facilities will be given a written notice four weeks in advance of the test date.

k) If system-operating conditions force cancellation of the test, a new date will be set in accordance with the above parameters.

l) Voltage reduction load relief capability shall be measured by each participant with control over transmission/distribution facilities during system-wide voltage reduction tests.

13.4.2 Load Shedding

Every second month, the System Operator will conduct a simulated manual load shed test to train the System Operator and participant with control over transmission/distribution facilities personnel in all aspects of manual load shedding procedures. These tests will be conducted in accordance with Operating Procedure No. 7 - Action in an Emergency, to the maximum extent possible. Tests will deviate from actual load shed operations in the following manner.

a) All verbal load-shedding directives will be preceded and concluded with the statement, "This is a test. Do not shed load".

b) Operators will not open breakers or disconnect actual load, but instead, will observe or estimate the amount of load that would have been shed on the circuit had it been an actual load shedding operation. These tests may be used to help verify a participant with control over transmission/distribution facilities's capability to reduce system load by as much as fifty percent.

Operators will report the amount of load that would have been shed and the length of time to do it to their next highest dispatching authority. The System Operator will issue reports on each simulated manual load shedding test. The report will specify the amount of load relief attained and the time interval to attain the load shed during the test.

Operating Procedure No. 14

14 TECHNICAL REQUIREMENTS FOR GENERATION, DISPATCHABLE AND INTERRUPTIBLE LOADS

14.1 Introduction

14.1.1 This procedure describes the minimum technical requirements for a Resource to enter and continue to participate in the power market, as described in Market Rules. This operating procedure addresses technical requirements, and not the offer characteristics of market products, that may include parameters of a technical nature. This procedure is meant to assure, in conjunction with the market structures, that the bulk power supply of the Moldova Control Area conforms to proper standards of reliability. This procedure is also meant to establish technical requirements to insure that each Resource has accurate metered data available for dispatch center control and Settlement.

14.2 Technical Requirements for Generating Units

14.2.1 This section describes the basic technical requirements that a Generator must meet to be considered in the offer process.

14.3 Generator Defined

14.3.1 A Generator must be defined consistently for all applications of the System Operator. That is, it must be defined in the same manner for the purposes of bidding, dispatch and Settlement.

14.3.2 A defined Generator, composed of multiple generating units, is anticipated in the case of most combined cycle units. The Participant's right to combine physical generating units to create a Generator for offers, dispatch and Settlement is governed by the following rules:

14.3.3 a) Generating units being combined must either be at the same physical site or be part of a project that, by its technical nature, requires coordinated control of the various units being combined to form a Generator.

14.3.4 b) A Participant is free to combine generating units to form a defined Generator of up to XX MW.

14.3.5 The System Operator will consider if such a combination of generating units interferes with effective control of probable constraints or accurate determination of system losses, Operating Reserve and Automatic Generation Control (AGC) capabilities. The appropriateness of these combinations will be reviewed on a continuing basis.

14.3.6 Offers may only be submitted for a defined Generator.

14.3.7 The System Operator will only perform Settlement functions for a defined Generator.

14.3.8 To define a Generator, the Participant is required to submit any technical data with respect to a Generator that the System Operator determines to be necessary for the System Operator to carry out its responsibility to reliably and efficiently operate the power system. The Participant is responsible for submitting and maintaining all requested data.

14.4 Telemetering and Revenue Metering

14.4.1 Telemetering for the Generator must meet the requirements for speed and accuracy per Operating Procedure, 'Metering and Telemetering Criteria'. Telemetering must be maintained and calibrated by the Participant on an ongoing basis per Operating Procedure , 'Metering and Telemetering Criteria'.

14.4.2 Revenue metering must meet System Operator accuracy requirements per Operating Procedure , 'Metering and Telemetering Criteria'. Meter readings must be forwarded to the System Operator for Settlement, in a timely manner, as required in the Market Rules and Procedures. The Participant is responsible for the maintenance and calibration of revenue metering per System Operator requirements.

14.5 Communication and Control

14.5.1 Any control equipment used to start, stop or vary the output of the Generator, from a remote location, must meet the requirements set in Operating Procedure, 'Metering and Telemetering Criteria', relative to speed, accuracy and data channel requirements. Such equipment must be maintained by the Participant according to requirements contained in Operating Procedures "Maintenance of Communications, Computers, Metering and Computer Support Equipment".

14.5.2 Each dispatchable Generator must have a dedicated voice communication telephone for System Operator dispatching purposes.

14.6 Operational Considerations

14.6.1 A Generator will be dispatched as directed by the System Operator in accordance with Operating Procedure 'Operating Responsibilities and Authority of the System Operator', and the operating characteristics submitted by the Participant.

14.6.2 Both the annual overhaul and short term maintenance of the Generator will be done in accordance with System Operator Generator maintenance scheduling procedures per Operating Procedure , "Unit Outages."

14.6.3 The Participant must, at all times, comply with all applicable switching and tagging procedures in effect by the authorities governing switching and tagging operations in the field.

14.7 Voltage Control

14.7.1 The MVAR production of a Generator is an important factor in the reliable operation of the Control Area. Participants are to support system voltage and reactive needs at the direction of the System Operator. The System Operator and the Satellite Dispatch Centers have the authority to direct the Participant to deviate from the normal voltage schedule to address operating situations.

14.7.2 The Participant must keep and maintain a voltage regulator on all generating units comprising a Generator. It is the responsibility of the Participant to maintain the voltage regulator in good operation and promptly report to the System Operator any problems that could cause interference with its proper operation. The Participant should normally operate with the automatic voltage regulator in service. The Participant must promptly report to the System Operator if and when the automatic voltage regulator is removed from service.

14.8 Governor Control

The Participant is obligated to provide and maintain a functioning governor on all Generators with a capability of ten (10) MW or greater. The governor should be set in accordance with industry standards unless technical considerations dictate otherwise. The Participant is responsible for periodic testing and maintenance of the governor.

14.9 System Protection

14.9.1 At a minimum, the Participant must install and maintain protection systems on units that are large enough to affect the systems of others. The Participant shall be responsible for maintaining and upgrading this protection system.

14.9.2 Relay maintenance and testing should not occur while a generating unit is on-line that would in any way degrade the level of system protection or system reliability provided by the unit.

14.9.3 To the extent possible, underfrequency relays for Generators must be set lower than underfrequency relays used to disconnect customers for the purpose of balancing load and generation.

14.10 System Stabilizers

14.10.1 Where stabilizer equipment is installed on a generating unit for the purpose of maintaining system stability, it is the responsibility of the Participant to maintain the stabilizer equipment in good operation, and promptly report to the System Operator any problems interfering with its proper operation. The Participant should normally operate with the stabilizer in service. The Participant must promptly report to the System Operator or the appropriate dispatch center, as appropriate, if and when the stabilizer is removed from service.

14.11 Black Start Capability

14.11.1 Participants that elect to provide black start capability from their generating units, and such generating units have been incorporated in System Operator system restoration plans and/ or as defined by Operating Procedure, “Black Start Capability Testing,” must maintain that equipment in good operating condition. The Participant must promptly report to the System Operator, any problems interfering with the black start capability of such designated generating units.

14.12 Technical Requirements for Dispatchable Loads

(To be developed)

14.13 Technical Requirements for Interruptible Loads

(To be developed)

14.14 Auditing and Testing

14.14.1 The System Operator reserves the right to conduct unannounced audits or tests of a Generator, Dispatchable Load or Interruptible Load to verify its compliance with the technical requirements as set forth in this procedure. These audits may be conducted on a periodic basis or because the System Operator has a reason to suspect a deficiency. On site audits will be coordinated with the Participant and scheduled during normal business hours.

14.14.2 The System Operator will promptly notify a Participant in writing in the event of a failed audit or observed deficiency. Records detailing a Participant's deficient performance will be delivered to that Participant on request within X business days of System Operator's receipt of the audit results. In case of a failed audit or observed deficiency, the System Operator will work with the Participant to correct the problem as soon as possible.

14.14.3 Failure to comply with the technical requirements of this procedure may cause the Resource to be unable to perform in the markets. This does not include compliance failures due to circumstances beyond the reasonable control of the Participant, such as transmission, distribution or communications outages. The System Operator will determine the Resource's ability to perform in the markets when not in compliance with the requirements of this procedure.

14.15 Revenue Metering

14.15.1 The System Operator has the right to audit testing and calibration records, and order and witnesses the testing of revenue metering per Operating Procedure, 'Metering and

14.16 Equipment Maintenance

14.16.1 Participants shall keep detailed records of equipment maintenance. The System Operator shall have the right to review the maintenance and test record for auditing purposes to insure that the equipment (voltage regulator, governor, , telemetering and communication and control equipment) is maintained in good operation.

14.17 Protection Systems

14.17.1 The System Operator shall have the right to review protection studies, elementary diagrams, relay setting documents, relay maintenance reports and relay calibration records in order to audit compliance with the protection criteria

15 OPERATING PROCEDURE NO. 15

16 TRANSMISSION SYSTEM DATA

16.1 Introduction

16.1.1 The System Operator and the Participants require data, which defines and represents the physical characteristics, ratings, and operational limits of all elements of the high voltage transmission system. This data is used to determine limits within which the bulk power system is operated and to develop accurate system models.

16.1.2 The timely submission of accurate and complete data is critical to real time operations, operations planning, the maintenance of the models and to the power system security applications which operate on those models.

16.1.3 It is the responsibility of the Participants to submit the required data for new, reconductored, and reconfigured facilities to the System Operator in a timely manner. The owner Participant is responsible for determining and reporting the data defined in this procedure for all system elements. The System Operator is responsible for acquiring the data for that portion of any system element, which is beyond the border of a participant.

16.1.4 Typical lead times required for full implementation of changes to system models and security applications are thirty (30) to sixty (60) days. For this reason, Participants are encouraged to submit one-line diagrams and data implementation forms for new or reconfigured (reconductored) facilities as far in advance of the in service/effective date as possible. Construction diagrams may be submitted as an aid to timely implementation, to be followed up with final diagrams when the final diagrams are available.

16.2 Submission of Data Defining Transmission System Elements (Station One-Line Diagrams)

16.2.1 Individual station one-line schematics diagrams of all substations 110 kV and above are required to be on file for use by the System Operator. The System Operator will use these diagrams to define the substation model and the transmission elements for which must be submitted.

16.2.2 New or revised station one-line diagrams must be submitted to the System Operator Planning and Analysis Department. Revised one-line diagrams must be accompanied by specific documentation of the items changed. Documentation of items changed may be accomplished by notation in a revision box on the diagram or by cover memo.

16.2.3 The System Operator will review submitted data to verify that it is complete and to insure that it conforms with the explanation of terms. It must be recognized that the System Operator's responsibility to insure conformance with the explanation of terms is limited to checking that the data is reasonable and that there is consistency between items of data.

16.2.4 The System Operator will notify the Participant of any discrepancies found. It is the Participant's responsibility to provide the System Operator with a revised form, which includes the corrected data. Once the new submittal is received, implementation will proceed.

16.3 Transformer

16.3.1 Data is to be provided for all Generator Step-up Transformers with a high side voltage of 110 kV and above. Data for transformers connecting at lower kV may be requested under special circumstances.

16.3.2 A separate form must be provided for each transformer. The System Operator will provide System Operator Identification Numbers for all transformers. All data items must be completed for each winding unless these instructions specifically indicate otherwise. An explanation must be provided in the remarks section for any other data items not completed.

16.3.3 Manufacturers' name plate information may be submitted under separate cover but is not required.

16.3.4 All voltage data item responses are to be in kV unless otherwise indicated in these instructions.

16.4 Transmission Facility Rating, Characteristic, and Operational Data

(To be further developed)

16.4.1 a) Transformer - Phase Shifting

16.4.2 b) Capacitor/Reactor

Operating Procedure No. 16

17 LOAD POWER FACTOR CORRECTION

17.1 Introduction

17.1.1 Large power transfers on the transmission system and the provision of first contingency coverage requires that adequate reactive capacity be maintained on generators to sustain system voltages. Participants should not rely so heavily on reactive support from the transmission system that voltages cannot be maintained during stressed system conditions. On the other hand, Participants should not over-correct their loads such that reactive power (VARs) are being exported to the transmission system creating high voltages and degrading system stability. To provide for reliable operation, the reactive requirements of the system must be analyzed from a regional standpoint. The analysis must recognize the following:

a) Large power transfers within or between pools/areas can significantly increase reactive power (I^2X) losses;

b) The loss of 330KV transmission lines can load remaining lines more heavily and significantly increase I^2X losses;

c) Outages of major generators not only remove significant reactive sources but can also result in large MW transfers and increased I^2X losses;

d) Power transfers can reach a point where not enough VARs can be transmitted to or away from an area to maintain acceptable voltages;

e) The system can reach a state where even though voltages appear adequate, most available VAR generation is being used and a contingency might seriously degrade voltages and reactive performance, and may necessitate emergency action;

f) During light load periods, line and cable charging may produce voltages so high that circuits must be opened to reduce voltages;

g) Insufficient reactive compensation in a single area can impact neighboring areas and affect overall pool operation.

17.2 Load Power Factor Requirement

17.2.1 This Operating Procedure establishes ranges of acceptable load power factors to provide for reliable system reactive performance. The ranges of acceptable load power factors consist of a bandwidth of load power factor expressed as a function of load level. The bandwidth between a pair of limiting curves represents the range of recommended load power factor. The ranges are determined through loadflow simulations at various load levels.

17.2.2 The Transmission service has responsibility to monitor and manage power factor and add/remove reactive resources to meet the Area's established ranges of acceptable load power factors. Generating units connected to the bulk power transmission system and sub-transmission system are expected to comply with the voltage schedules and operate according to reactive capability curves.

17.2.3 The System Operator will conduct an annual review of the most recently developed curves to determine if they require updating. Factors to be considered are significant changes in the transmission and/or generation system, load growth, etc. If it is determined that the curves require updating, the necessary studies will be undertaken by the System Operator.

17.3 Testing Criteria

17.3.1 A general criteria is used to provide for uniform levels of reliability within all the areas. Two rules are applied during various stages of testing: zero VAR interchange and minimum/maximum voltage. For this analysis, zero VAR interchange makes each area responsible for its own reactive needs and minimizes the need to consider voltage/reactive performance of areas outside of the area being studied. Although zero VAR interchange is rarely achieved in actual operation, it builds into the load power factor requirements a level of reliability beyond that provided by the outage of lines and generators.

17.3.2 The two rules described above are used to establish minimum and maximum load power factors for each area at three discrete load levels: heavy (100%), medium (75%), and light load (40%). A curve connects the three minimum points and another curve connects the three maximum points. The bandwidth between these two curves represents the range of load power factors that establish the standard. Diagram 2 shows an example of minimum and maximum load power factors as a function of load level.

17.4 General Testing Procedure

17.4.1 Export and import conditions are evaluated for each area at each load level with the most restrictive load power factor becoming the area standard. To develop minimum load power factor limits the loadflow case is biased toward low voltage conditions. To develop maximum load power factor limits the loadflow case is biased toward high voltage conditions. Low voltage/minimum load power factor testing is done in two distinct stages. Stage I testing establishes load power factors that are verified in Stage II testing. The most restrictive load power factor of the two stages becomes the area standard. High voltage/maximum load power factor testing involves only Stage I testing.

17.5 Low Voltage Bias - Stage I Test

17.5.1 In Stage I testing the study area is biased towards low voltage conditions. Then the worst contingency is simulated along with all normal operator actions that can be achieved in ten minutes. Finally, the load power factor of the study area is adjusted until voltages are at minimum values (generally 95% or a pre-determined specific limit for a critical bus) or the area begins to violate zero net VAR interchange. Note that both rules are respected in this stage.

(To be further develop)

17.6 Low Voltage Bias - Stage II Test (Allowing VAr Interchange)

(To be further develop)

17.6.1 In Stage II testing all areas are set to their minimum load power factor as determined in Stage I. Each study area is then biased towards low voltage conditions, one at a time. The worst contingency is then simulated allowing VAR interchange.

17.7 Assumptions for Load Flow Development

17.7.1 Generator Data and Dispatch

a) Scheduled voltages are controlled within specified limits.
b) Reactive capabilities for large generators are the VAR high limits.
c) Station service loads are modeled for all larger generators.
d) A dispatch is performed assuming all resources are available.

17.7.2 2. Bus Data

a) Initialize MW and MVAR load at each bus using projections for the appropriate load level. Use the total area MW and MVAR load to determine area load power factor and apply this load power factor to each bus in the area (uniform load power factor).
b) Loads are independent of voltage (constant P and Q).
c) Shunt capacitors that are on the transmission system are modeled.

17.7.3 3. Transformers and Tie Lines

a) Automatic load tap changing is allowed in all tests.

VAR interchange between areas metered at the electrical midpoint of each tie line except where contracts specify entitlement to line charging.

Power Factor Survey Illustration

Step-down Transformer Load at Subtransmission/Distribution Level:

(4) MW
(5) MVAR

Step-down Transformer Losses

(6) MW
(7) MVAR

Generation on Subtransmission/Distribution Level:

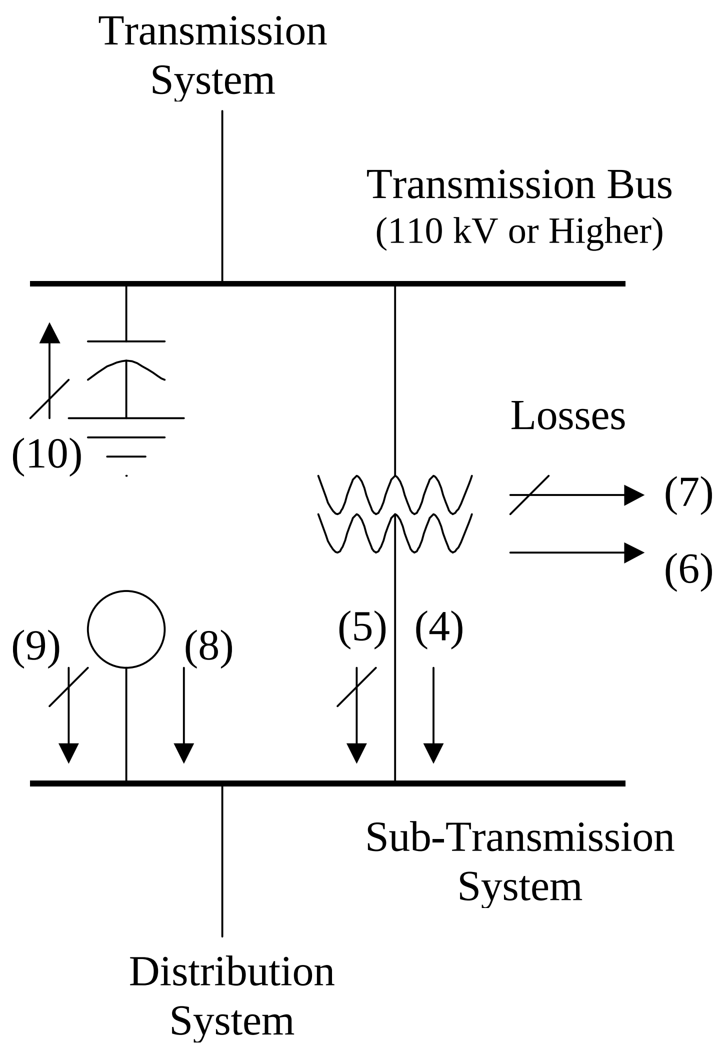
(8) MW
(9) MVAR

Capacitors installed on the Transmission System to Serve Area Load:

(10) MVAR

Total Load Served From Generation and Transmission System:

(11) MW = (4) + (6) + (8)
(12) MVAR = (5) + (7) + (9) – (10)



Operating Procedure No. 17

18 METERING AND TELEMETERING REQUIREMENTS

18.1 Purpose

18.1.1 These criteria establish standards for metering (measurement) and telemetering (data transmission) for the purposes of System Operator dispatching, market Settlement, Participant peak load determination and load power factor (lpf) measurement. The power system parameters, which the Participants are to meter and/or telemeter, are identified. Standards are established to ensure that the equipment, which Participants install, will provide an appropriate level of accuracy and/or appropriate recordings for audit purposes. Maintenance procedures and schedules to be followed by the Participants are prescribed so that the level of accuracy, which is attainable, will be realized.

18.2 Implementation

18.2.1 Participants shall have in-service or be progressing towards having in-service all the metering, recording or telemetering equipment necessary to meet the requirements of this operating procedure. The equipment standards for new and replacement installations, and the testing, calibration, and maintenance standards are applicable upon adoption of the operating procedure and all revisions.

18.3 Metering, Recording and Telemetering On Interconnections With Systems Outside Moldova Control Area

18.3.1 Overall Requirements

The metering and telemetering requirements for each transmission line interconnecting transmission facilities to systems outside of Moldova Control area are:

0 Instantaneous megawatts (MW) from all terminals of the line.

1 Instantaneous megavars (MVAR) from all terminals of the line

2 Megawatthours (MWh) per hour (energy per hour).

Instantaneous megawatts (MW) and megawatthours (MWh) per hour metering shall be at the same terminal of each interconnection.

18.4 INSTANTANEOUS MEGAWATTS AND MEGAVARS

18.4.1 This data must be telemetered to both System Operator and the participant of the interconnected system.

18.5 Megawatthours per Hour

18.5.1 There shall be a device at each interconnection facility to record the hourly billing watthours on site. In all new and upgraded installations, solid-state data recorders shall be installed.

18.5.2 The watthour data shall be compensated for line losses to the System Operator boundary. Megawatthours may be recorded and telemetered as a net or as two quantities, MWh IN and MWh OUT.

19 Metering and Recording For Settlements

19.1.1 Megawatthour (MWh) per hour (energy per hour) metering and recording is required for each Generator, Tie-Line interconnection point and delivery point as these assets.

19.1.2 The location of the metering terminals shall be reported to the System Operator by the registered Participant.

19.2 Generator

19.2.1 Generators directly connected to the transmission system shall be metered at the boundary delivery point or compensated to the boundary delivery point. Generator megawatthour compensation may be accomplished either automatically within the revenue metering or manually.

19.2.2 Generators not connected to the transmission system shall be metered net to the point(s) of interconnection with the participant(s) to which it is directly connected.

19.3 Tie-Line

19.3.1 Tie-lines connect a Participant to either another Participant or the transmission system.

19.3.2 Tie-lines shall be metered at the interconnection point or compensated to the interconnection boundary with the other Participant or the transmission system boundary as appropriate.

19.4 Load - participants

19.4.1 Every load must have a physical megawatthour meter or be determined on an hourly basis as an allocation of a physical watt hour meter.

19.4.2 Required metered quantities include Participant dispatchable loads, interruptible loads, generators less than X MW modeled as negative loads and generator off-line station service.

19.5 Generator and Load Telemetering Criteria

19.5.1 Instantaneous metering is required for all generators and loads eligible to participate in hourly power market. The instantaneous metering must meter a generator or load as it is bid in the Market.

19.5.2 The following quantities are to be telemetered and made available to the System Operator dispatch communications network:

- Generator net MW (may be converted to net of generators in Participant dispatch computer) gross MVAR (and breaker status must be telemetered).
- Dispatchable Load MWs must be telemetered.
- All generating stations X MW or larger.
- Other transmission busses which, for reliable transmission operations, require regulation and control.
- MW and MVAR from every terminal of all 330 kV and 110 kV lines.
- MW and MVAR from each 330 kV and 110 kV transformer.
- The status of all 330 kV and 110 kV breakers.
- The status of 110 kV breakers, which affect the transfer capability of or within the bulk power system.
- The status of switching devices which affect the transfer capability of or within the bulk power network.
- The tap positions of all 330 kV autotransformers and all phase-shifting transformers which are equipped and operated for tap changing under load.
- Other telemetered data to be determined on a case-by-case basis which are required for bulk power system operation (static VAR compensator stations, capacitor/reactor status, frequency).

19.6 Equipment Standards for New and Upgraded Installations

19.6.1 This section specifies standards for metering, recording and telemetering equipment that Participants install in all new and upgraded installations. This section does not preclude Participants from maintaining existing equipment with like or improved parts. This section does require Participants to choose equipment that meets these standards when old equipment is removed and new equipment is installed.

19.6.2 All new and upgraded installations should be tested and/or certified to be Year 2000 compliant in accordance with industry standards.

19.6.3 All metering devices used shall conform to applicable National standards as amended from time to time.

19.6.4 All new and upgraded metering, recording and telemetering installations shall meet the following standards:

19.6.5 The design accuracy of individual components as well as overall systems shall conform to the standards. Solid-state equipment (meters, recorders, transducers, etc.) shall be installed.

19.6.6 Participants are advised that additional quantities, including delivered and received megavar-hours per hour (MVARh) in conjunction with megawatthours per hour (MWh), will likely require metering, recording and telemetering as a result of future revisions to this OP. Participants are encouraged to install meters and recorders that are capable of measuring and recording these quantities.

19.6.7 For all grounded wye system metering, three element meters and transducers shall be used. For all delta system (ungrounded) metering, two or three element meters and transducers may be used. All bi-directional transducers shall have a milli-amp output into a load of no more than 10K ohm.

- A solid-state data recorder installed at the metering location. A Participant may elect to use on-site plant computers as recorders when they are used to record accumulated pulses. Data shall be retrieved from recorders by on-site or remote interrogation. Where the Participants mutually agree to the need for joint access to this recorded data, remote communications equipment is recommended to be installed.

- An RTU at the meter location scanned hourly by a centrally located dispatch or data acquisition computer. The computer must periodically retrieve accumulated pulses via coded digital transmission for all hours.

19.6.8 Remote accumulation of continuous pulse signals received from metering equipment does not satisfy the recording device requirement. These existing installations shall be upgraded to include either of the types of equipment listed above.

19.6.9 All data recorders shall be synchronized in time, within an accuracy of +/- 2 minutes, periodically and when they are installed or returned to service after maintenance or repair.

19.6.10The pulse rates selected for input to the data recorder shall be sized such that the pulse rates utilize the resolution capabilities of the recorder.

19.6.11Compensation for line and/or transformer losses, when used shall be accomplished by applying correction continuously. This correction shall be accomplished by programming the compensation in the solid-state meter or by another appropriate method.

19.6.12Upon the occurrence of a partial or system-wide blackout, substations, control centers and communications systems will be dependent upon backup systems and/or internal power sources. The availability of data communications circuits will be critical to effective restoration.

19.6.13To ensure that reliable data communications paths are available should a blackout occur, criteria have been developed, against which existing circuits should be measured. When existing facilities do not meet the criteria, appropriate steps should be taken to correct the situation. The following are the criteria for the RTU and related equipment located at substations rated at 110 kV and above, generating stations and for the communications equipment between these stations.

19.6.14 All data communications equipment shall meet the following standards:

a) The equipment should not be dependent on alternating current (ac) as a power source. The basic power source should be the station battery or an independent battery, as appropriate. The battery should be capable of supporting the anticipated load for at least eight hours.

b) If for some reason the substation or generating station equipment must be powered by an ac source, the equipment must be able to operate independently from the ac power source for the rest of the facility. An auxiliary power source would be required.

c) The basic power source for the communications terminal equipment, including the modem, at the substation or generating station, should be a battery. If this equipment is dependent on an ac power source, it must be able to operate independently from the ac power source to the rest of the facility or operate without a power source.

d) Diagnostic (loop back schemes) and protective devices on communication circuits must be passive or fail into a safe, communicating mode upon loss of station service power.

e) Whenever possible, participants owned facilities should be available as the primary or backup means of data communication.

f) The equipment should operate over the normal range of temperatures that could exist when the ac power source is lost and as a result, air conditioning or heating is lost.

g) The configuration/connection of communication circuits should be designed so that a problem on one circuit does not cause a problem on another (should not be propagated).

h) Alarms should be provided to an appropriate location indicating the status of batteries, backup equipment, etc.

i) Dedicated telephone circuits should be used. Any collection points where circuits terminate should have a backup or independent power source.

19.7 Testing, Calibration and Maintenance Standards

19.7.1 Each Participant is responsible for properly maintaining its metering, recording and telemetering equipment in accordance with applicable standards as amended from time to time. The specific standards for testing, calibration and maintenance *will* put forth in this Section.

19.8 Watt-hour Meters

19.8.1 All watt-hour meters shall be tested by comparison to a solid-state watt-hour standard which is traceable to the accepted International Standards (“ xxxxxxxxxx.”)

19.8.2 All watt-hour meters shall be tested at operating or nameplate voltage under the following three conditions:

- Full Load at the meter Test Ampere rating and unity power factor.
- Light Load at 10% of the meter Test Ampere rating and unity power factor.
- Power Factor at the meter Test Ampere rating and 0.5 power factor lag.

NOTE: Solid-state meters used in bi-directional applications shall be tested for both forward (delivered) and reverse (received) accuracy.

19.8.3 The series test results must be within the following accuracy limits:

Test Condition	Accuracy Limit
Full Load (FL)	+/- 0.2% error
Light Load (LL)	+/- 0.3% error
Power Factor (PF)	+/- 0.5% error

19.8.4 In addition to the “As-Found” series tests, all induction watt-hour meters shall have an “As-Found” individual element balance test performed. The individual elements shall be tested at operating or nameplate voltage, at Full Load (FL) test amps, and unity power factor. The individual element test results must be within 1.0% of each other.

19.8.5 If the “As-Found” test results are outside the stated accuracy limits, then the meter shall be adjusted as closely as practicable to 0.0% error. The final “As-Left” test results shall be within the stated accuracy limits.

19.8.6 Any induction watt-hour meter found outside of +/- 2.0% error or any solid-state watt-hour meter found outside the +/- 0.5% error (at any test condition) shall be adjusted and scheduled for replacement as soon as practicable.

19.8.7 Meters with compensation for line and/or transformer losses shall be series tested with and without the compensation activated at the test points.

19.8.8 All meters must be tested at least once a year.

19.8.9 Data recording equipment, this includes internal and external to the meter data recorders, shall be checked monthly by comparing a summation of the hourly demand readings with the kilowatt-hours registered on the watt-hour meters for the same period of time. The difference in the sum of hourly demand readings and the kilowatt-hours registered on the watt-hour meter should be less than the value of the watt-hour meter transformer ratio multiplier. When this difference is greater, the installation shall be reviewed and tested if the discrepancy is not explainable.

19.8.10 The continuity of meter readings should be maintained during tests either by use of a portable meter or other suitable methods. A watt-hour meter test may be made during a period of no load or when the load is constant and the reading adjusted upon completion of the test. Pulse data should likewise be adjusted upon completion of the test. When this is not practical, other methods must be used to segregate pulses registered due to the test from pulses due to registration of power flow.

19.9 Instrument Transformers

19.9.1 Scheduled tests of instrument transformers are not required unless all other tests fail to explain a discrepancy; then testing shall be performed. The testing procedure shall conform to the manufacturer's specifications.

19.10 Test Equipment

19.10.1 Test equipment used in the calibration of instrument transformers or transducers should be certified to values of accuracy and precision, which are at least twice as accurate as the required accuracy of the equipment under test. Solid-state watt-hour standards of 0.1% or better accuracy shall be used in the testing of watt-hour meters. All watt-hour standards should be certified correct every twelve months.

19.10.2 The tests and calibrations should be performed at ambient temperatures recommended by the manufacturers of the test equipment and the equipment under test.

19.10.3 Instrumentation used to check the tone modulating frequency for data transmission should have a minimum definition of 0.001 Hertz. The dc ammeter or voltmeter used to measure input signals shall have a minimum accuracy of +/- 0.05%.

19.11 Record Keeping and Auditing

19.11.1 The Participants are to maintain records of the testing and calibration of all metering and telemetering equipment, which is required to be installed according to the provisions of this operating procedure. The records are to include such information as the dates of testing and calibration, whether the equipment was found to be within accuracy standards without recalibration, whether recalibration was performed and accuracy achieved by recalibration. These records are to be retained for the current year plus the previous calendar year and are to be available to the System Operator.

19.12 Notifications

19.12.1 When metering and telemetering equipment associated with Participant interconnections is scheduled for maintenance, test or upgrade, interconnected Participants shall be notified at least two weeks in advance in order to have the opportunity to participate in or witness the maintenance, test or upgrade.

19.13 SECURITY OF METERED AND RECORDED DATA

19.13.1 Security shall be addressed to prevent unlawful, unintentional or unauthorized access to those portions of the firmware, software and data being collected that would have an effect on the metered and recorded quantities. This may be done using primary and secondary security codes or other appropriate means. This does not preclude the Participant from allowing read-only access to the data.

19.14 COMPLIANCE

19.14.1 Periodically, the System Operator conduct an audit survey of metering, recording devices and telemetering criteria to determine the degree of Participant compliance operating procedures requirements.

19.15 Interconnection Energy Billing Metering Accuracy Levels

Level I Accuracy (Conforming)

19.15.1 KWh metering that complies with this Operating Procedure that is:

19.15.2 Physically located at the high voltage point or agreed upon point of interconnection or not physically located at the high voltage point but continuously compensated (one second integration or less) for Transformer excitation watt losses and the Transformer and/or Line load resistive watt losses to the interconnection point.

Level II Accuracy (Acceptable Non-Conforming)   +/- 0.25% Risk Vs Level I

19.15.3 KWh metering that complies with this Operating Procedure except that it's not physically located at the PTF/Interconnection point but the recorded meter data is compensated through external software calculations for Transformer excitation watt losses and the Transformer and/or Line load resistive watt losses to the PTF/Interconnection point. Maximum one hour Loss integration period.

19.15.4 Compensation calculations includes both real power (kW) and reactive power (kVar or kQ) measurements. Voltage may be either measured or assumed constant. Reactive power measurement is optional if power factor is compliant with NEPOOL Operating Procedure #17 Load Power Factor Correction.

Operating Procedure No. 18

20 TRANSMISSION OPERATIONS

20.1 Introduction

20.1.1 This operating procedure describes reliability criteria for the analysis and operation of the Moldova power transmission system.

20.1.2 The rules in this document are used to determine data, methods and limits for operation of the Moldova high voltage transmission system (110 kV and above). The System Operator and participants use these data, methods and limits to operate the transmission system in accordance with this procedure.

20.2 Reliability Criteria for Transmission Operations

20.2.1 The Moldova transmission system is operated so that the most severe single contingency can be sustained without causing:

- equipment damage due to thermal overload,
- cascading thermal overloads,
- excessively high or low voltage or voltage collapse,
- unit or area instability,
- undamped oscillations.

20.2.2 Any single contingency should not cause the loss of other critical facilities or portions of the power system.

20.2.3 Two levels of transmission reliability are prescribed and define the condition of the power system. During Normal Conditions, the higher level of prescribed reliability is maintained. During Stressed or Emergency Conditions, a lower level of reliability is permitted to allow for increased operating flexibility and to minimize the impact on customers during power system emergencies.

20.2.4 Actions should be taken to establish and maintain Normal Conditions. Regular cycling between Normal and Emergency Conditions should be avoided. Operations and operations planning should not intentionally position daily operations into Emergency Conditions. Capacity deficiencies or the occurrences of multiple contingencies are some reasons why Emergency Conditions might exist.

20.2.5 This operating procedure includes specific definitions and criteria for these two levels of reliability.

20.3 Thermal Capacity Ratings for Transmission Facilities

20.3.1 Normal Rating

Transmission facility loadings up to this rating can be experienced without incurring loss of life above design criteria.

The following Emergency ratings (LTE, STE and DAL) may involve loss of life or loss of tensile strength in excess of design criteria and should not be deliberately scheduled.

20.3.2 Long Time Emergency (LTE) Rating

This rating is intended to fit a daily load cycle (12 hours summer, 4 hours winter). A facility may operate up to this rating provided that its loading is returned to or below the Normal rating during off-peak hours.

20.3.3 Short Time Emergency (STE) Rating

This is a fifteen-minute rating. If a facility operates at this rating for more than fifteen minutes, equipment will suffer thermal damage. Facility loadings above the LTE rating but at or below the STE rating must be reduced to or below the LTE rating within 15 minutes.

20.3.4 Drastic Action Limit (DAL)

This is an immediate action rating. If a facility operates at this rating for more than five minutes, equipment will suffer thermal damage. Facility loadings above the STE rating but at or below the DAL must be reduced to or below the LTE rating within 5 minutes.

20.3.5 Standard Summer and Winter Transmission Facility Ratings

Transmission facility ratings can be based on over stressing terminal equipment such as wave traps, current transformers, etc. or heating of the line conductor.

Summer ratings should be used from April 1 through October 31. Winter ratings should be used from November 1 through March 31.

20.4 Normal Conditions

20.4.1 The highest level of transmission reliability is achieved during non-stressed or **Normal Conditions** on the Moldova power system. In general, this level of reliability is accomplished by satisfying **Normal** criteria for a wide range of contingencies (**Normal** contingencies) using a limited set of operator actions (**Normal** actions). More specifically, for all stability related and inter-area thermal and voltage/reactive operations, all **Normal** contingencies are applicable. For thermal and voltage/reactive operations within Moldova power system that do not jeopardize the reliability of areas outside Moldova, only five of the seven NORMAL contingencies are considered. This approach is consistent with the NPCC criteria philosophy that the basic criteria are not necessarily applicable in the portions of a member system where instability or overloads will not jeopardize the reliability of the bulk power system. The following sections describe these NORMAL Criteria, NORMAL Contingencies and NORMAL Actions.

20.4.2 Normal Criteria

a) Generation and transmission service is scheduled to provide Moldova load and operating reserve as prescribed in Operating Procedures while covering **Normal** contingencies.
b) Pre-contingency loadings of transmission facilities should not exceed **Normal** ratings.
c) **Normal** contingencies should not cause, or result in, loadings beyond STE ratings. Flows between LTE and STE must be reduced to or below LTE as soon as possible and definitely within 15 minutes. If studies show that operators would not be able to reduce flows to or below LTE within 15 minutes, action should be taken (if possible) such that **Normal** contingencies would not cause, or result in, loadings above LTE ratings.
d) Normal contingencies should not cause instability, unacceptably high or low voltage or voltage collapse.
e) Any automatic reclosing and subsequent manual reclosing before adjusting generation should not cause instability of the transmission system.

20.5 Normal Contingencies

20.5.1 For all stability related and inter-area operations, protection should be provided for all of the **Normal** contingencies listed below.

20.5.2 For thermal and voltage/reactive operations within Moldova, protection should be provided for the **Normal** contingencies listed in a. through e. below.

20.5.3 During typical conditions with all major transmission facilities in-service, **Normal** contingencies should be covered in thermal and voltage/reactive operations if the occurrence of these contingencies could jeopardize the reliability of areas outside of Moldova.

20.5.4 During less frequent conditions when a major transmission facility is out-of-service, **Normal** contingencies f. and g. need not be covered if the outage substantially reduces transfer limits based on **Normal** contingency f and g.

a) A permanent three-phase fault on any generator, transmission circuits, transformer or bus section with normal fault clearing.
b) Loss of any element without a fault.
c) A permanent phase to ground fault on a circuit breaker with normal fault clearing. (Normal fault clearing time for this condition may not always be high speed.)
d) Simultaneous permanent loss of both poles of a direct current bipolar facility without an AC fault.
e) The failure of a circuit breaker associated with an special protection system (SPS) to operate when required following: loss of any element without a fault; or a permanent phase to ground fault, with normal fault clearing, on any transmission circuit, transformer or bus section.

f) Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and, therefore, can be excluded.

g) A permanent phase to ground fault on any transmission circuit, transformer, or bus section with delayed fault clearing. (Delayed fault clearing is consistent with correct operation of a breaker failure scheme and its associated breakers, or of a backup relay scheme with an intentional time delay.)

20.6 Normal Actions

20.6.1 The System Operator and participants will continuously assess system conditions and implement the **Normal** actions described below to maintain or restore transmission reliability to **Normal** conditions.

20.6.2 Actions for contingencies that affect all areas within Moldova

If a contingency will impact only area within Moldova, the following **Normal** actions should be implemented as required:

a) System Operator initiated deviation from economic dispatch

- If the local area can be protected by deviation from economic dispatch, the System Operator and participants will provide such protection.
- If a local area cannot be protected by deviation from economic dispatch, System Operator may elect to waive contingency protection for the local area.

b) Use of special protection systems (SPS) or the preplanned opening of circuit breakers.

- Where possible, arm special protection systems (SPS).
- Manually set up generator tripping. This preplanned option of opening circuit breakers is limited to situations where previously documented studies have demonstrated that such breaker openings reliably mitigate the specific existing operating conditions and do not result in the loss of single contingency protection for other contingencies/facilities.

c) Weather sensitive transmission facility ratings

There are times when actual ambient conditions (temperatures and wind) are significantly different from those used to establish standard seasonal ratings. During those times, the use of temporary ratings based on actual ambient conditions may be warranted. Depending on the ambient conditions, the temporary ratings may be higher or lower than the standard seasonal ratings. When such weather conditions exist and a transmission facility is limiting, The System Operator or participant will identify the need for a temporary transmission facility rating based on actual weather conditions.

d) Deviation from economic dispatch

Deviate from economic dispatch and schedule generation to maintain normal transmission reliability, including generation not counted as operating reserve.

e) Switch transmission circuits

Open or close circuits to relieve transmission constraints. This action can only be implemented when authorized by the System Operator and when previously documented studies have demonstrated that such circuit openings reliably relieve the specific existing conditions and do not result in the loss of protection for other contingencies/facilities.

20.7 Emergency Conditions

20.7.1 The system is in an EMERGENCY Condition if **Normal** Criteria is violated. A lower level of reliability is permitted when operating under EMERGENCY Conditions provided that all appropriate **Normal** Actions have been initiated to restore NORMAL Criteria. This level of reliability meets EMERGENCY Criteria for a less stringent set of contingencies (EMERGENCY Contingencies) using EMERGENCY Actions. Exposure to reliability levels below EMERGENCY Conditions should not exist for more than 30 minutes.

20.8 Emergency Criteria

20.8.1 Generation and transmission facilities are adequate to supply Moldova load while covering only EMERGENCY Contingencies.

20.8.2 Pre-contingency facility loadings may be between NORMAL and LTE if EMERGENCY Contingencies would not cause loadings beyond LTE ratings. Loadings should be returned to or below the NORMAL rating after the daily load cycle.

20.8.3 EMERGENCY Contingencies should not cause loadings beyond STE ratings. Flows between LTE and STE must be reduced to or below LTE as soon as possible and definitely within 15 minutes. Automatic devices (SPS), switching to set up a facility to trip upon occurrence of a specific contingency or, preplanned post-contingency operator responses are required if DAL ratings are used.

20.8.4 EMERGENCY Contingencies should not cause instability, unacceptably high or low voltage or voltage collapse.

20.8.5 Any automatic reclosing should not cause instability of the transmission system.

20.9 Emergency Contingencies

20.9.1 A permanent three-phase fault on any generator, transmission circuits, transformer or bus section, with normal fault clearing.

20.9.2 The loss of any element without a fault.

20.10 Emergency Actions

20.10.1EMERGENCY Actions should be taken to maintain or restore power system conditions to at least those prescribed for operations under EMERGENCY Conditions. In general, all appropriate and timely NORMAL Actions should be exhausted before taking EMERGENCY Actions. EMERGENCY Actions should be taken before NORMAL Actions if the NORMAL Actions cannot be completed in time to relieve a thermal overload above LTE, prevent voltage collapse, or restore protection for EMERGENCY Contingencies within 30 minutes. Any unused long term NORMAL Actions should be taken to allow for the cancellation of EMERGENCY Actions.

a) Transmission Circuit Switching
In very well defined situations where it is clear that opening a transmission facility will alleviate a problem existing for a specific emergency situation, consideration will be given to opening such facility. This action, without pre-determined studies, documentation, and authority will only be initiated to prevent more severe EMERGENCY Action and must be reported immediately to the Transmission Provider.

b) Operating procedure No4 and Operating procedure No7 Emergency Actions include:

1. Operating procedure No4 5% voltage reduction, requiring more/less than 10 minutes.

2. Operating procedure No4 voluntary load curtailment by large industrial and commercial customers. Radio and TV appeals for voluntary load curtailment. Voluntary load curtailment by customers.

3. Operating procedure No7 load shedding.

The following sections provide more detail on when it would be appropriate to take EMERGENCY Actions.

20.11 Pre-Contingency Emergency Actions

20.11.1 EMERGENCY Actions may be needed to meet EMERGENCY Criteria even though a contingency has not occurred. Such pre-contingency EMERGENCY Actions will be taken when NORMAL Actions are exhausted or can not be completed in a timely manner and there would be insufficient time after an EMERGENCY Contingency to contain the impact to a small/local area. Pre-contingency EMERGENCY Actions are to be initiated when a potential EMERGENCY Contingency threatens large portions of Moldova load or could possibly cause a split of the bulk power system due to post-contingency voltage collapse, rapid cascading thermal overloads or, system instability. Pre-contingency EMERGENCY Actions should also be taken when a potential EMERGENCY Contingency poses the same threats to Areas outside of Moldova or jeopardizes the reliability of the Moldova external interconnections.

20.11.2 Shift operators are responsible to keep appropriate Supervisors at the System Operator and participants advised as to conditions that might necessitate management review of the need to implement EMERGENCY Actions on a pre-contingency basis.

20.12 Planned Immediate Post-Contingency Emergency Actions

20.12.1 If an EMERGENCY Contingency does not risk system stability but would result in low or gradually declining voltages or thermal loadings between STE and DAL, specific voltage reduction or load shedding plans should be established before the contingency for implementation immediately after the contingency. Post-contingency EMERGENCY Action should be established and coordinated with the participants before the need for implementation arises. If automatic devices are being used, their actions should be completed in a matter of cycles or seconds after the contingency. Manual actions should be completed as soon as possible after the contingency (seconds if possible) but definitely within the one-two minutes required to prevent voltage collapse or cascading thermal overloads. Post-contingent circuit loadings between STE and DAL must be reduced below LTE immediately and definitely within five (5) minutes.

20.13 Post-Contingency Operation

20.13.1 If a contingency involves the loss of a transmission circuit(s), operators should attempt to reclose the circuit(s) within 5 minutes unless otherwise specified in specific policies and/or procedures. If reclosure is successful, the system should be back to its original state and normal operation should resume. If reclosure is unsuccessful or the contingency involved the loss of generation or load, operators should assess system conditions and perform appropriate NORMAL and EMERGENCY Actions to restore NORMAL and EMERGENCY Conditions. When possible, coverage for NORMAL Contingencies should be restored using NORMAL Actions.

20.13.2 Post-contingency Actions should meet the following time requirements:

- Rapidly declining critical transmission voltages should be stabilized as quickly as possible (within one-two minutes) using pre-determined EMERGENCY Actions, including voltage reduction and/or load shedding.

- Post-contingent transmission facility loadings between STE and DAL should be reduced below LTE immediately and definitely within 5 minutes using pre-defined EMERGENCY Actions including voltage reduction and/or load shedding plans.

- Post-contingent transmission facility loadings between LTE and STE ratings should be reduced below LTE as soon as possible and definitely within 15 minutes using appropriate NORMAL and/or EMERGENCY Actions.

- Coverage for EMERGENCY Contingencies should be restored within 30 minutes using appropriate NORMAL and/or EMERGENCY Actions.

20.14 Transmission System Analysis

20.14.1 A. Scope of Analysis

Transmission system analysis is required to:

- Identify significant contingencies and system conditions during which contingencies can adversely impact system operation and;
- Develop data, methods, operating guidelines and procedures which, when implemented, will provide reliable operation of the bulk power system per the criteria in this document.

Short term thermal analysis is performed on a continuous basis and coordinated with appropriate participants and adjoining Control Areas. Long term thermal analysis is done on a seasonal, annual or as required basis and is coordinated with adjoining Control Areas.

20.15 Classifying System Responses To Contingencies

20.15.1 Contingencies fall into one of the following categories depending on their impact on system reliability:

20.15.2 Contingencies Critical to Areas External to Moldova

This type of contingency either involves the loss of an inter-Area transmission facility (thereby reducing inter-Area transfer capability) or has more severe consequences on an external Area than the most severe contingency in the external Area. The possibility of thermal overloads, excessive voltage drops, or undamped oscillations on the interconnection should be considered when assessing the impact of these contingencies. These contingencies are critical to interconnected system reliability.

20.15.3 Contingencies Critical to Large Areas of Moldova or Bulk Power Transfers within Moldova.

This type of contingency can threaten large areas within Moldova in two ways. In one case, the contingency could split an area away from the bulk power transmission system due to cascading thermal overloads, voltage collapse or system instability. Further breakup would likely occur in the islanded area. The remaining bulk power system would be left with a substantial deficiency or excess of power. In the other case, the contingency could cause the loss of another critical transmission facility, thereby significantly reducing transfer capability on the bulk power system and seriously impairing the ability to serve customer load. These contingencies are critical to Moldova transmission reliability.

20.15.4 Contingencies that Affect Small/Local Areas within Moldova

This type of contingency affects only a relatively small area within Moldova and does not impair reliability of the bulk power system. The System Operator will provide contingency protection, if possible, by deviating from economic dispatch. Otherwise, the Transmission Provider involved will be contacted through the appropriate Satellite. The Transmission Provider may elect to grant a waiver of contingency coverage.

20.16 Extreme Contingencies

20.16.1 Recognizing that the bulk power system can be subject to events that are more severe than NORMAL or EMERGENCY Contingencies, EXTREME Contingencies will be assessed to determine their effect on system performance. After due analysis and assessment of EXTREME Contingencies, Transmission Providers may utilize measures, where appropriate, to reduce the frequency of occurrence or to mitigate the circumstances that are indicated as a result of testing for such contingencies.